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BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

FILED

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INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST, D/B/A CITIZENS GAS & COKE UTILITY FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE AND APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES APPLICABLE THERETO, (2) AUTHORITY, TO THE EXTENT NECESSARY AS AN ALTERNATIVE REGULATORY PLAN, TO RECOVER THE GAS COST COMPONENT OF ITS NET WRITE-OFFS IN ITS GAS COST ADJUSTMENT FILINGS, (3) AUTHORITY PURSUANT TO 170 IAC 5-1-27(F) FOR A NON-GAS COST REVENUE TEST TO DETERMINE WHEN DEPOSITS ARE REQUIRED FOR EXTENSION OF FACILITIES, (4) APPROVAL OF OTHER CHANGES TO ITS GENERAL TERMS AND CONDITIONS FOR GAS SERVICE, AND (5) APPROVAL OF NEW DEPRECIATION ACCRUAL RATES	)	**CAUSE NO. 43463**

DIRECT TESTIMONY AND EXHIBITS OF LATONA S. PRENTICE and CHRISTOPHER H. BRAUN

On Behalf of Petitioner,
Citizens Gas & Coke Utility

Volume III

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March 18, 2008

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DIRECT TESTIMONY
of
LATONA S. PRENTICE

On
Behalf of
Petitioner

Citizens Gas & Coke Utility

Petitioner's Exhibit LSP

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. LaTona S. Prentice. My business address is 2020 North Meridian Street, Indianapolis, Indiana 46202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Board of Directors for Utilities ("the Board") of the Department of Public Utilities of the City of Indianapolis. The City is the successor trustee of a public charitable trust and acting through the Board manages and controls the municipally-owned gas utility that is the Petitioner in this proceeding and does business as Citizens Gas & Coke Utility ("Petitioner," "Citizens Gas" or the "Utility"). I am the Executive Director of Regulatory Affairs of Citizens Gas.

Q. HAVE YOU HELD ANY OTHER POSITIONS WITH CITIZENS GAS?

A. Yes. I began my employment with Citizens Gas in 1984 as an Accountant. During my employment with Citizens Gas, I also have held the positions of Budget & Rates Administrator, Budget & Operations Analyst, Rates and Operations Analyst, Rates Manager, Director of Budget & Rates, and Director of Regulatory Affairs.

Q. PLEASE DESCRIBE THE DUTIES AND RESPONSIBILITIES OF YOUR PRESENT POSITION AS THEY RELATE TO CITIZENS GAS.

A. As Executive Director of Regulatory Affairs, I am responsible for the development, implementation, and administration of Citizens Gas' rates and charges and Terms and Conditions for Gas Service. I prepare, or supervise the preparation of, accounting and financial adjustments, cost of service studies, and rate design testimony for Citizens Gas. Since 1986, I have been responsible for the preparation of cost of service studies, quarterly GCA changes, Manufacturing/Oil Division Net Revenue Trackers and Customer Benefit Distribution Trackers, and miscellaneous rate matters. I prepared, or supervised the preparation of, the schedules filed in connection with many of Petitioner's quarterly gas cost adjustments in Cause No. 37399.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from Ball State University in 1984 with a Bachelor of Science Degree in Accounting.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am the current Chairman of the American Gas Association ("AGA") Rate Committee, and a member of the AGA State Regulatory Committee. I also am a member and past Chairman of the Indiana Energy Association Rate Committee.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, on numerous occasions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes the overall revenue requirements of Citizens Gas (including the underlying adjustments to the financial results for the test year ended September 30, 2007), the proposed net write-off gas cost recovery mechanism, and the modification Citizens Gas proposes to the application of the Commission's rule governing main extensions.

FINANCIAL AND ACCOUNTING OVERVIEW

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGES 1 AND 2.

A. Petitioner's Exhibit LSP-1, pages 1 and 2, is the Summary of Pro Forma Revenue Requirement beginning with the twelve months ended September 30, 2007 (the test year for this proceeding) and the pro forma revenue requirement for Citizens Gas' operations. Column A is the actual per books income statement, which is consistent with Petitioner's witness John R. Brehm's Exhibit JRB-1. Column B shows the pro forma adjustments made to reflect the going-level of operations in order to reflect fixed, known, and measurable changes which will occur within twelve months following the end of the test year. Column C shows the pro forma revenue requirements at current rates reflecting the adjustments shown in Column B. Column D contains the pro forma adjustments necessary to produce the proposed revenue requirement and operating income. Column E shows the pro forma statement of operating income after adjusting for the proposed rate increase. Column F contains references to the pages of Petitioner's Exhibit LSP-1 and other witness exhibits containing the particular adjustments.

Q. IN YOUR OPINION, DOES COLUMN C OF PETITIONER'S EXHIBIT LSP-1, PAGES 1 AND 2, ACCURATELY REFLECT CITIZENS GAS'

OPERATIONS DURING THE TEST YEAR, AND ITS ANNUAL REVENUE REQUIREMENT ADJUSTED FOR FIXED, KNOWN, AND MEASURABLE CHANGES WHICH WILL OCCUR WITHIN TWELVE MONTHS FOLLOWING THE END OF THE TEST YEAR?

A. Yes.

Q. **HOW ARE THE AMOUNTS SHOWN IN PETITIONER'S EXHIBIT LSP-1, PAGES 1 AND 2, COLUMNS B THROUGH E, USED ELSEWHERE IN THE UTILITY'S CASE-IN-CHIEF?**

A. Columns B through E of Petitioner's Exhibit LSP-1, pages 1 and 2, summarize the overall revenue requirement of the Utility and the adjustments used to arrive at the pro forma revenue requirement. Petitioner's witness Craig A. Jones used information from Petitioner's Exhibit LSP-1, pages 1 and 2, to prepare the Utility's cost of service study and rate design. I have tried to keep the adjustments simple and direct, and to avoid smaller, less important adjustments to our revenue requirement to help reduce the complexity of the case.

Q. **PLEASE SUMMARIZE THE PRO FORMA REVENUE REQUIREMENT.**

A. As shown on line 17 of Column E, the pro forma revenue requirement for Citizens Gas totals $463,087,907. Column D, line 17, of this Exhibit indicates that Citizens Gas requires an increase in base rate revenues of $19,695,023 in order to provide it with an opportunity to earn an operating income of $31,603,446, as indicated on line

59 of Column E. The net operating income from the proposed rates and charges must be sufficient to meet the Utility's annual debt service obligations and provide funds for making necessary extensions and replacements in excess of depreciation. Petitioner's Exhibit LSP-1, page 3, shows in a pie chart the Utility's pro forma revenue requirement by cost category.

DETAILED DESCRIPTION OF ACCOUNTING ADJUSTMENTS

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGES 4 THROUGH 8.

A. Petitioner's Exhibit LSP-1, page 4, is a comparison of the test year customers, therms, and revenue by customer class to the pro forma numbers. Petitioner's Exhibit LSP-1, pages 5 through 8, set forth the pro forma adjustments to Citizens Gas' test year gross margin and, in the aggregate, represent a net decrease in test year margin of $2,660,794 (see Petitioner's Exhibit LSP-1, page 1, column B, line 25).

OPERATING REVENUES AND GAS COSTS:

Q. ARE PETITIONER'S PRO FORMA GAS REVENUES AND GAS COSTS DETERMINED IN THE SAME MANNER AS PRESENTED IN CITIZENS GAS' LAST RATE CASE, CAUSE NO. 42767?

A. No. In Cause No. 42767, Citizens Gas utilized a computer model and bill frequency study to determine its pro forma gas revenues and gas costs. On pages 10 and 11 of the October 19, 2006 Order in Cause No. 42767, the Commission found that

"Citizens Gas failed to demonstrate that its computer model produced the more accurate pro forma adjustment." The OUCC had proposed the use of the "weather normalization adjustment methodology approved by the Commission in Vectren North's last rate case, i.e., Cause No. 42598." The Commission found that "the weather normalization methodology in Vectren North's last rate case is 'transparent in how the normal weather adjustment is derived.'" The Commission further found that the "use of the tail block rates for each customer class is a reasonable alternative to a bill frequency study, and has been customarily used and accepted in numerous other rate cases."

As a result of the Commission's findings in Cause No. 42767, Citizens Gas has determined its pro forma gas revenues and gas costs using the same methodology Vectren North used in Cause No. 42598, by adjusting test year customers, therms, and revenues using a weather normalization adjustment to arrive at pro forma revenues.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 5.

A. Petitioner's Exhibit LSP-1, page 5, shows the pro forma margin to be derived from gas sales and transportation based upon normal weather. Normal weather was determined by reference to the 30-year normal heating degree days as published by NOAA. The test year heating degree days were 8.3% warmer than normal, and the winter months (September through May) were 7.0% warmer than normal. Therefore, the net margin increases. The impact of this adjustment, revenue less cost of gas, is an increase in test year margin of $3,047,950, as shown on line 7 of page 5 of Petitioner's Exhibit LSP-1.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 6.

A. Petitioner's Exhibit LSP-1, page 6, represents a net 20 customer increase from the test year number of customers to the pro forma number of customers and their associated usage. The pro forma number of customers identifies customers whose service was disconnected or added during the test year and adjusts the number of customers to remove from or add to the test year monthly customer numbers by class during the months that had not reflected those removals or additions. In addition, we added customers to the extent we know they will be connected during the 12 months following the end of the test year. The number of customers is defined by the number of active meter points. It is possible for some services to be served by more than one meter. The net change in customers/meters by class is found in Petitioner's Exhibit LSP-1, page 6, line 1. The test year margin is decreased by $645,604 to reflect the increased number of customers and their associated usage.

Q. WHY DOES A NET INCREASE OF 20 CUSTOMERS RESULT IN A TEST YEAR MARGIN DECREASE?

A. A large number of customers migrated from the large volume class (Rate D5) to the general heat class (Rate D4), which has a lower test year facilities charge, but a higher test year delivery charge than the large volume class. In addition, 220 customers (defined as the number of meters for purposes of the rate case) migrated from the large volume class to the high load class (Rate D9), which had a slightly higher test year facilities charge offset by a smaller delivery charge than the large volume class.

Q. WHAT IS THE PURPOSE OF PETITIONER'S EXHIBIT LSP-1, PAGE 7?

A. The purpose of Petitioner's Exhibit LSP-1, page 7, is to remove the change in unbilled revenue less gas cost recorded in the test year of $862,492, as the pro forma revenue and cost of gas reflect a calendar month billed basis, rendering unbilled revenue unnecessary. In addition, Petitioner's Exhibit LSP-1, page 7, adjusts test year decoupling, correction factors, automatic meter reading ("AMR") charges, billing demand revenue, and miscellaneous adjustments to pro forma levels, and removes normal temperature adjustment ("NTA") revenue, storage true-up revenue, and interruptible and non-metered gaslight revenue.

The test year decoupling revenue adjusts the billed margin revenue by class to the decoupling margin authorized in the Commission's August 29, 2007 Order on Rehearing, as further adjusted for the Indiana Utility Receipts Tax on gas costs and actual customer numbers. The test year billed margin revenue was weather normalized to determine pro forma margin revenue. The resulting pro forma margin revenue was adjusted to arrive at the authorized decoupling margin. The pro forma decoupling revenue reflects a $1,508,169 increase to the amount of test year decoupling revenue; given the fact that decoupling was only in effect for the final month of the test year (September 2007).

The test year AMR charges were increased $52,928 to adjust to the current level of AMR devices, and to incorporate the proposed AMR charge of $64 per unit. The proposed AMR charge increase is discussed in the testimony of Craig A. Jones. The test year billing demand revenue was decreased by $353,245 to adjust to the current demand volumes, and to annualize to the current demand rate authorized in the Commission's August 29, 2007 Order on Rehearing in Cause No. 42767.

The test year NTA revenue of $1,191,846 was eliminated as a result of the weather normalization adjustment. Because the weather normalization adjusts pro forma revenue to reflect normal weather, any pro forma NTA revenue would equate to $0. The amount of test year storage true-up revenue also was eliminated, as the amount of this revenue is unpredictable, is fully offset by a gas cost, and is not fixed, known, or measurable.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 8.

A. Petitioner's Exhibit LSP-1, page 8, reflects the pro forma adjustments necessary to normalize the facilities charge rates, delivery charge rates, and gas cost rates to pro forma levels. The test year facilities charge rates and delivery charge rates changed in October 2006 to reflect the Commission's October 19, 2006 Order in Cause No.

42767, and the delivery charge rates changed again on September 1, 2007, as a result of the Commission's August 29, 2007 Order on Rehearing in Cause No. 42767. In addition, the average facilities charge rate varies between test year and pro forma as a result of the distribution of customers among the various meter classes in Rates D3, D4, D5, and D9. The delivery charge rate also varies between test year and pro forma as a result of the distribution of sales volumes among the rate blocks of Rates D2, D3, D4, D5, and D9. The pro forma increases in facilities charge rates, delivery charge rates, and gas cost rates were $416,919, $1,633,500, and $13,078,840, respectively.

Q. HOW WERE PRO FORMA NATURAL GAS COSTS DETERMINED?

A. Pro forma gas costs were based upon the gas sales volumes determined with the weather normalization adjustment and customer additions and deletions, along with current gas price projections, and an appropriate mix of gas supply sources which will meet operational needs for gas supplies and minimize costs. The Utility's pro forma gas supply will rely upon 38 million dekatherms of purchased gas (including unaccounted for gas) net of injections to and withdrawals from company-owned and leased storage. These volumes have been priced at current prices to arrive at pro forma natural gas costs.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 9.

A. Petitioner's Exhibit LSP-1, page 9, depicts the various adjustments to test year revenues necessary to bring those revenues to an ongoing level. The deduction of $2,431,158 on line 2 redistributes to "other revenues" the test year revenue from customer-specific contracts served under Gas Rate 30. This adjustment was made so Mr. Jones would be able to allocate the revenues among the remaining customer classes, effectively reducing the revenues required from each customer class. Gas Rate 30 customers are served pursuant to the terms of customer-specific contracts. Because the rates of customers served under Gas Rate 30 will not change as a result of this proceeding, allocating costs to them would be inappropriate. Rather than allocating a portion of the revenue requirement to the Gas Rate 30 customers, Citizens Gas is allocating the revenue received from Gas Rate 30 customers to the remaining customer classes, thus reducing the amount of revenues that needs to be recovered from those classes.

Q. WHAT IS THE PURPOSE OF PETITIONER'S EXHIBIT LSP-1, PAGE 10?

A. The purpose of Petitioner's Exhibit LSP-1, page 10, is to show the amount of "other revenues" included in the Utility's proposed pro forma revenue requirement. The adjustments in this exhibit reflect the counter-adjustments described in Petitioner's Exhibit LSP-1, page 9, necessary to bring "other revenues" to an ongoing level, as well as adjustments to arrive at pro forma "other revenues."

Q. WHAT IS INCLUDED IN "OTHER REVENUES?"

A. "Other revenues" include all the miscellaneous charges, as well as revenues derived from gas customers and 3rd Party Suppliers. Specifically, "other revenues" include reconnection and collection fees, returned check charges, late payment charges, smaller miscellaneous items, Citizens Energy Select ("CES") administration fees and weather hedge settlement revenue.

Q. HOW DID YOU ADJUST THESE ITEMS OF "OTHER REVENUES?"

A. I decreased the adjusted test year "other revenues" by $4,441,237. Of this amount, $162,001 reflects increased late payment charges ("LPC"). I used a three-year historical average of LPC to normalize the test year LPC.

CES administration fees were reduced by $55,208 to remove the effects of CES administration fees associated with Usage Balancing Service, Basic Usage Balancing Service, and Non-Performance Charges. The costs associated with balancing services and 3rd Party Supplier non-performance charges vary widely, are unpredictable, and are not sufficiently fixed, known, and measurable to be included in the pro forma revenue requirements. The revenues received from these administrative services are intended to offset incremental operating costs and gas costs associated with providing those services. Neither the gas costs nor the incremental operating costs are reflected in the pro forma revenue requirements.

Miscellaneous other gas revenue was reduced by $2,575,870 to remove $2,488,000 of test year weather hedge revenue and other, smaller annualization adjustments. Because the revenue requirements and revenues are based upon "normal" weather, any weather hedge the Utility might have in place would not result in a pay out. Therefore, it is appropriate to remove the test year revenue received from the Utility's weather hedge.

The last adjustment to "other revenues" is to remove the cost of gas from Gas Rate 30 revenues. Similar to the gas costs associated with CES administrative fees, the Gas Rate 30 revenues related to gas costs are due to balancing provisions of those customer-specific contracts.

OPERATIONS & MAINTENANCE EXPENSE:

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 11.

A. Petitioner's Exhibit LSP-1, page 11, is a computation of pro forma operations and maintenance expenses. Petitioner's Exhibit LSP-1, page 11, line 2, reflects a decrease of $2,069,297 to reclassify company-use gas to gas costs. In addition, I have included as adjustments to operations and maintenance expense increases in insurance costs and the accumulated and ongoing price volatility mitigation costs.

Pro forma revenue requirements were increased by $433,588 to partially fund the Utility's Energy Efficiency Portfolio. In the Cause No. 42767 Stipulation and Settlement Agreement ("42767 Agreement") approved by the Commission on August 29, 2007, a copy of which is attached as Petitioner's Exhibit LSP-2, Citizens Gas' Energy Efficiency Portfolio and Oversight Board were created to allow Citizens Gas "to focus its efforts to effectively implement and expand existing energy efficiency programs directed at the core residential and commercial uses of gas and . . . build customer awareness of the availability of the energy efficiency programs." Paragraph 18 of the 42767 Agreement established the initial funding level for the Energy Efficiency Portfolio – Phase 2 at or below $2.5 million. "Of this amount, $470,588 will be recovered in Citizens' base rates, with increments above that amount to be recovered through the [Energy Efficiency Funding Component]" of the Citizens Gas Energy Efficiency Adjustment rider. Due to the late implementation of the Energy Efficiency Portfolio (September 1, 2007, subsequent to the Commission's August 29, 2007 order), Citizens Gas' test year expense for its Energy Efficiency Portfolio was $37,000; therefore, I made a $433,588 adjustment to include the total $470,588 Energy Efficiency Portfolio expense in the revenue requirement.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 12.

A. The adjustment on Petitioner's Exhibit LSP-1, page 12, reflects a three-year historical average of pension fund contributions. The adjustment for the gas division is reflected as an adjustment to operations & maintenance expense, while the CSS adjustment is reflected as an adjustment to general & administrative expense. The test year expenses of $1,123,556 and $1,840,492 for the gas division and CSS operations, respectively, reflect accrual accounting. These funding contributions result in pro forma decreases to the test year expenses of $191,792 and $1,259,269 for the gas division and CSS, respectively.

Q. WHY DOES CITIZENS GAS REFLECT CASH FUNDING OF THE PENSION PLAN IN THE REVENUE REQUIREMENTS, RATHER THAN THE ACCRUAL EXPENSE?

A. The statute governing municipal utility ratemaking (IC 8-1.5-3-8) prescribes cash revenue requirements methodology for ratemaking purposes. In many instances, the accrual method and the cash method of determining a revenue requirement result in a similar number. In some cases, however, the difference between the two accounting methodologies is significant. The pension revenue requirement is an example of one of those differences. The total decrease between the test year expense and the pro forma cash requirement for pension was nearly $1.5 million.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 13.

A. Petitioner's Exhibit LSP-1, page 13, line 3, shows the pro forma net write-off non-gas cost of $917,109. The test year provision for uncollectible expense was decreased by $2,092,891 to reflect the combined effect of an increase in total net write-offs commensurate with the proposed revenues in this case, offset by moving the gas cost related net write-offs to be recovered with the gas costs. As is more fully explained later in my testimony, Citizens Gas is proposing to continue to recover through its base rates the non-gas cost component of its net write-offs at a fixed ratio of 0.8% of gas sales revenue, and to recover through its GCA rates the net write-off gas costs at a fixed ratio of 0.8% of total gas costs. The three-year historical average net write-offs as a percent of five-month lagged total gas revenues amounts to 0.8%. Multiplying the pro forma gas sales revenues net of gas costs at present rates of $114,638,611 by 0.8% results in a pro forma net write-off non-gas cost at present rates of $917,109, which is $2,092,891 less than the test year provision for uncollectible expense of $3,010,000.

Q. WHY DID YOU USE NET WRITE-OFFS AS A PERCENT OF FIVE-MONTH LAGGED TOTAL GAS REVENUES?

A. A period of five months must pass before uncollected revenues can be written off. Therefore, taking net write-offs as a percent of the revenue that was billed five months prior to the write-off month is a more appropriate indicator of the level of net write-offs. I conservatively used a three-year average of net write-offs as a representative level of ongoing write-offs. However, Citizens Gas anticipates a substantial increase in the amount of net write-offs compared to the amount experienced in recent years. The higher than expected 2007 property tax increase has caused (or will cause) a strain on household budgets. In addition, the current adjustable rate mortgage increases (also known as the sub-prime lending crisis) have caused many customers' mortgage payments increasing to a level which they are unable to pay. Because very little, if any, down payment or equity was required at the time of purchase, borrowers have no economic incentive to retain their houses, resulting in foreclosure or abandonment, often leaving behind unpaid gas bills. For example for the four months ended January 2008, Citizens Gas' net write-offs have doubled compared to the same period in 2005 and 2006. The fiscal year-to-date January net write-off comparisons are as follows:

2006	$1,048,000	2.0%
2007	$1,098,000	2.0%
2008	$2,233,000	4.4%

Q. **HAVE YOU PROVIDED FOR INCREASED PAYROLL EXPENSES?**

A. Yes, I have. Petitioner's Exhibit LSP-1, page 14, depicts the increase in pro forma payroll expense. The increase in payroll was determined using current levels of employees and annualized pay rates that will go into effect in 2008. The overall pay rate adjustment reflects pay raises, recently-added positions, and eliminated manufacturing division-related positions, as discussed in Mr. Brehm's testimony. The adjustment for the gas division is reflected as an adjustment to operations & maintenance expense, while the CSS adjustment is reflected as an adjustment to general & administrative expense. The annualization of regular payroll results in a gas division increase of $2,317,679 and a CSS increase of $2,330,668. To regular payroll, I have added overtime and supplemental pay, based upon the level at which these expenses occurred during the test year. Further, in order to determine the amount of payroll to be expensed (as opposed to capitalized), I have deducted the amount of pro forma payroll associated with capital projects, which is a capital cost recoverable from customers as part of extensions and replacements. Overall, the gas division and CSS payroll expenses have been increased by $3,118,258 and 4,883,673, respectively. Of the $4,883,673 pro forma adjustment to CSS payroll, $2,451,750 is an accounting-related correction to the executive incentive plan, as explained in the testimony of Mr. Brehm.

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENT SHOWN ON PETITIONER'S EXHIBIT LSP-1, PAGE 15.

A. Petitioner's Exhibit LSP-1, page 15, shows the increase in employee benefits expense. As with the payroll adjustment, the adjustment for the gas division is reflected as an adjustment to operations & maintenance expense, while the CSS adjustment is reflected as an adjustment to general & administrative expense. The employee benefits expenses are $249,340 lower and $305,094 higher than the gas division and CSS test years, respectively.

Q. WHAT EMPLOYEE BENEFIT EXPENSES ARE NOT DIRECTLY RELATED TO THE LEVEL OF PAYROLL?

A. Employee health insurance expense and post retirement benefits fit that description. The pro forma adjustment to employee health insurance expense is based upon information provided in a November 2007 report issued by Mercer Human Resource

Consulting, LLC, which indicated employers should expect an average increase of 5.7% in 2008. In each of the last five years, employee health care expenses have steadily increased. The gas division pro forma employee insurance has been increased by $258,382, while the CSS expense has been increased by $272,497 from the test year expense.

The gas division's pro forma post retirement benefits adjustment is $689 less than the test year, while the CSS adjustment is $18,043 greater than the test year, as prepared by the Utility's actuary McCready and Keene, Inc. However, an adjustment of ($410,000) also was made to gas division employee benefits associated with the agreed upon FAS106 (i.e., post retirement benefits) recovery in Cause No. 41605, as shown on pages 2 and 3 of Petitioner's Exhibit LSP-2.

Q. **WHAT WERE THE TERMS ASSOCIATED WITH FAS106 COST RECOVERY IN CAUSE NO. 41605?**

A. On August 27, 2002, Citizens Gas, the Office of Utility Consumer Counselor ("OUCC"), and the Citizens Industrial Group executed the Stipulation and Settlement Agreement in Cause No. 41605, which is attached as Petitioner's Exhibit LSP-2 (the "Unbundling Settlement Agreement). The Commission approved the Unbundling Settlement Agreement (see Petitioner's Exhibit LSP-3) on December 11, 2002. As a condition of establishing the customer benefit tracker ("CBT"), certain conditions were imposed on Citizens Gas' recovery of deferred and going-level FAS106 costs.

The parties to the Unbundling Settlement Agreement agreed that the Utility "will retain $410,000 each year (not limited by the twelve year amortization period) from the CBT Available Funds for Citizens' ongoing annual FAS106 costs." Because $410,000 of Citizens Gas' ongoing post retirement benefits are "recovered in rates" through an adjustment to the CBT, the ongoing post retirement benefits to be included in revenue requirements have been reduced by that amount.

Q. PLEASE DESCRIBE THE ADJUSTMENTS ON PETITIONER'S EXHIBIT LSP-1, PAGE 16.

A. Adjustments to capitalized credits were made to adjust the test year loadings to pro forma by increasing the revenue requirements by $209,455 and $9,364 for the gas division and CSS, respectively.

Q. PLEASE DESCRIBE THE ADJUSTMENT ON PETITIONER'S EXHIBIT LSP-1, PAGE 17.

A. In the previously-described Unbundling Settlement Agreement, another condition of establishing the CBT was to "recover in rates" through the CBT credit mechanism the FAS106 transition obligation. The parties to the Unbundling Settlement Agreement agreed that the FAS106 transition obligation costs accumulated as of the date of the final order in that cause would be recovered through the CBT mechanism over the first twelve CBT filings. Because the amortization of the unbundling case's FAS106 transition obligation is "recovered in rates" through the CBT, the $451,032 test year amortization of those costs has been eliminated from the revenue requirements.

Q. **PLEASE EXPLAIN THE REMAINING ADJUSTMENTS TO GENERAL AND ADMINISTRATIVE EXPENSES SHOWN ON PETITIONER'S EXHIBIT LSP-1, PAGE 18.**

A. Several additional adjustments were made to general and administrative expenses for costs related to CSS depreciation, company use gas, insurance, regulatory expenses, and general office facilities maintenance normalization. In addition, as discussed by Petitioner's witness John R. Brehm, an adjustment was made to the allocation of the remaining CSS expenses to recognize the closure of the manufacturing division. The CSS depreciation was reclassified from general & administrative expense to depreciation to facilitate the offset to extensions & replacements in the determination of the pro forma revenue requirement. Pro forma CSS insurance costs are $96,867 higher than the test year in recognition of increased insurance premiums.

Similar to the previously-described amortization of the unbundling case's FAS106 transition obligation that is "recovered in rates" through the CBT, 50% of the unbundling case's FAS71 costs were to be amortized and recovered in rates through the CBT. Therefore, $346,344 test year amortization of those costs has been eliminated from the revenue requirements, offset by the three-year amortization of the cost of this rate case, netting to a $146,942 pro forma decrease to regulatory expense. The general office has been under renovation, so to normalize general office facility maintenance expense; the test year amount has been reduced by $695,011.

To recognize the closure of the manufacturing division, an adjustment was made to reduce the remaining test year CSS non-labor expenses by $692,812, and increase the CSS allocation factor to the gas division for the remaining CSS non-labor expenses from 70.3% in the test year to pro forma 76.3%, resulting in a net increase to the test year of $502,030.

Q. **PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 19.**

A. The pro forma level of depreciation expense shown on Petitioner's Exhibit LSP-1, page 19, line 5, is based on the utility plant in service at September 30, 2007, adjusted for items to be closed to plant during the following twelve months and the applicable 3.10% composite depreciation accrual rate currently in effect (stand-alone gas division depreciation accrual rate is 2.86%), as described by Mr. Donald Clayton. The pro forma increase in depreciation expense is $362,383.

<u>TAXES:</u>

Q. **HAVE YOU MADE A COMPUTATION REGARDING PRO FORMA PAYROLL TAXES?**

A. Yes. This calculation is shown on Petitioner's Exhibit LSP-1, page 20. I applied the payroll tax rates to the Utility's pro forma taxable payroll subject to the tax to arrive at a pro forma increase to gas division payroll tax expense of $181,184, and to CSS payroll tax expense of $215,821.

Q. HAVE YOU MADE AN ADJUSTMENT TO PROPERTY TAX EXPENSE?

A. No. Due to the current state of flux with respect to the determination of the amount of property tax, I did not make a pro forma adjustment to Property Tax Expense.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 21.

A. Petitioner's Exhibit LSP-1, page 21, describes the pro forma increase in Indiana Utility Receipts Tax ("IURT") expense. The test year IURT reflects the tax on Citizens Gas' total revenues. In the pro forma calculations, the IURT on gas cost revenue is reflected in the pro forma gas costs, and as a result, only the IURT on non-gas revenue is reflected in this adjustment. The pro forma non-gas cost revenue at current rates is multiplied by the 1.4% utility receipts tax rate to produce a $4,000,852 decrease in IURT expense at present rates.

PROPOSED REVENUE INCREASE:

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 22.

A. Petitioner's Exhibit LSP-1, page 22, shows the calculation of the increased revenue requirement for Citizens Gas necessary to provide operating income of $31,603,446. The required operating income is determined by grossing up the pro forma increase in revenue requirement found on Petitioner's Exhibit LSP-1, page 2, column C, line 59, by Indiana Utility Receipts Tax and net write-off non-gas cost. A total proposed increase in revenue requirements of $19,695,023 is required in order to produce an operating income of $31,603,447.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 23.

A. Petitioner's Exhibit LSP-1, page23, is a calculation of the net write-off non gas costs applicable to the proposed increase in revenue requirements, and is calculated by applying the 0.8% net write-off percent to the proposed increase.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT LSP-1, PAGE 24.

A. Petitioner's Exhibit LSP-1, page 24, is a calculation of the Indiana Utility Receipts Tax applicable to the proposed increase in revenue requirements, and is calculated by applying the 1.4% tax rate to the proposed increase.

Q. PETITIONER'S EXHIBIT LSP-1, PAGE 2, REFLECTS A REVENUE REQUIREMENT FOR ANNUAL DEBT SERVICE. DO YOU SPONSOR AN EXHIBIT THAT CALCULATES THE AMOUNT OF ANNUAL DEBT SERVICE?

A. No. The revenue requirement for debt service is set forth on Petitioner's Exhibit JRB-3, which is attached to the testimony of John R. Brehm.

Q. PETITIONER'S EXHIBIT LSP-1, PAGE 2, ALSO REFLECTS A REVENUE REQUIREMENT FOR EXTENSIONS & REPLACEMENTS. WHERE IN THE UTILITY'S CASE-IN-CHIEF IS THAT REVENUE REQUIREMENT DESCRIBED?

A. The adjustment to the test year level of extensions & replacements, and a description of the revenue requirement for extensions & replacements, are provided in the testimony and exhibits of Citizens Gas witness Christopher H. Braun.

NET WRITE-OFF RECOVERY

Q. PLEASE DESCRIBE WHAT CITIZENS GAS IS PROPOSING REGARDING THE RECOVERY OF ITS NET WRITE-OFFS.

A. Citizens Gas is proposing to continue to recover through its base rates the non-gas cost component of its net write-offs at a fixed ratio of 0.8% of gas sales revenue, and to recover through its GCA rates the net write-off gas costs at a fixed ratio of 0.8% of total gas costs. This proposed cost recovery mechanism for net write-offs will continue to provide an incentive for Citizens Gas to diligently manage its net write-offs, and Citizens Gas will recover from its customers net write-off gas costs at the fixed ratio of 0.8%. This methodology will not provide for full recovery of actual net write-off gas costs experienced by Citizens Gas; however, it will mitigate the risk to Citizens Gas of under recovering net write-off gas costs caused by gas price volatility. The effect of this approach will be to remove $2,556,977 of gas cost related net write-offs from recovery in base rates.

Q. HOW DID YOU CALCULATE THE AMOUNT OF 0.8% FOR THE NET WRITE-OFF AS A PERCENT OF GAS SALES REVENUE?

A. I divided the three year historical average net write-offs by the average five month lagged gas sales revenue to arrive at a fixed net write-off ratio of 0.8%.

Q. WHAT IS THE BASIS FOR THE CITIZENS GAS NET WRITE-OFF GAS COST RECOVERY PROPOSAL?

A. As an Indiana local distribution company, Citizens Gas incurs gas costs to provide reliable delivery of natural gas to its customers. The GCA is intended to provide for the timely recovery of the total cost of gas purchased for delivery to customers on a dollar-for-dollar basis. The gas cost adjustment mechanism allows gas utilities to adjust rates to account for changes in their gas costs, and by definition gas costs include "other expenses relating to gas costs as shall be approved by the commission." In addition, IC 8-1-2-42(g)(3)(D)(i) and (ii) allows gas utilities to include in prospective gas cost adjustment rates the difference between the actual gas costs experienced by the utility during the latest recovery period and <u>the actual gas costs recovered</u> by the GCA rates in effect during the same recovery period (emphasis added). The historical application of the GCA has determined whether actual gas costs experienced by the utility have been recovered by presuming all gas costs billed to customers (i.e., gas volumes sold multiplied by the applicable GCA rate) are actually paid by customers. In reality, when customers do not, or can not, pay their gas bills, and when attempts to collect the arrearages have been unsuccessful, the utility ultimately writes-off those amounts owed to the utility as bad debt. Of the amount written off, gas costs are by far the most significant portion of the customer's bill (in today's environment, upwards of 75% or more of the customer's bill). Once written off, they become gas costs that have not been, and will not be, recovered.

Q. **WHY IS INCLUDING THE ENTIRE NET WRITE-OFF COST IN BASE RATES INSUFFICIENT TO PROVIDE RECOVERY OF GAS COST WRITE-OFFS?**

A. Historically, the net write-off costs for Citizens Gas have been quite volatile. Petitioner's Exhibit LSP-5, identifies Citizens Gas' net write-offs for each of the last thirteen years. Net write-offs during the first six years of that period were relatively stable. With the exception of 1997 (which was the first year of high gas prices), net write-offs each year were within approximately $500,000. Net write-offs averaged approximately $2.0 million and topped out at $2.1 million (compared to the bad debt expense allowed in Cause No. 39066 of $1.8 million). However, the last seven years of that 13-year period, 2001 through 2007, tell a completely different story. The Utility's net write-offs during those seven years fluctuated between $2.6 million and $6.1 million—as much as $4.3 million more than the authorized bad debt expense which was included in our base rates at the time. Extreme fluctuations in the Utility's operating costs from year to year, as has been the case with its net write-offs, can be detrimental to the Utility by increasing its net write-offs and reducing operating income and cash flow.

Absent recovery of net write-offs apart from base rates, the amount of net write-offs that exceed the amount authorized for recovery in base rates is <u>never recovered</u> by the Utility. Or stated differently, in 2007, the actual net write-offs were nearly half the amount authorized for recovery in Cause No. 42767. In my opinion, the Commission should use its authority under the Alternative Utility Regulation Statute, IC 8-1-2.5, (to the extent the proposal cannot be approved under traditional regulation) and decline to exercise its jurisdiction in part as it relates to the traditional approach to recovery of net write-offs and approve the alternative regulatory plan Citizens Gas has proposed in this Cause, which includes recovery of the net write-off gas cost through the GCA mechanism. In doing so, I believe the Commission will serve the public interest as the proposed GCA treatment will be beneficial to customers and Citizens Gas as an "energy utility." Therefore, in my opinion, at a minimum, Citizens Gas should be afforded the opportunity to recover its statutorily-allowed gas costs, through the GCA mechanism.

Q. PLEASE DESCRIBE WHY IN YOUR OPINION CITIZENS GAS SHOULD BE ALLOWED TO RECOVER ITS NET WRITE-OFF GAS COSTS THROUGH THE GCA MECHANISM.

A. There are two primary drivers of the Utility's net write-offs: gas prices and weather. A secondary driver is the local economy. Each of these drivers is largely outside of our control. Fluctuations in the price of natural gas and variable weather result in volatile net write-offs. As the cost of natural gas increases, customer bills increase. Cold weather further exacerbates the situation because cold weather drives higher natural gas prices, increased customer consumption, and the result is higher unpaid gas bills. When customers receive higher bills, it means more customers are unable to pay their bills. In addition, a softening economy contributes to even more people being unable to pay their bills. Increased gas prices and gas price volatility, brief periods of cold weather that increased customer gas consumption, and a decline in the local economy combined to result in net write-offs from 2001 to 2006 that are significantly higher than the amount of bad debt expense allowed in the base rates of Citizens Gas that were in effect at the time. Conversely, the actual net write-offs in 2007 were significantly lower than the recoverable bad debt expense allowed in most recent rate case for Citizens Gas, Cause No. 42767.

Q. **WHY WERE THE 2007 NET WRITE-OFFS LOWER THAN THE RECOVERABLE BAD DEBT EXPENSE ALLOWED IN CAUSE NO. 42767?**

A. The recoverable bad debt expense allowed in Cause No. 42767 was based upon data available at the time (i.e., 2004), which gave every indication that write-offs would continue at a pace greater than 1% of revenues. Process improvements and other circumstances have resulted in reduced net write-offs since 2005.

Fiscal years 2002 through 2004 were heavily impacted by the rise in natural gas cost. The extreme gas cost spike occurred in 2001; however, because of the natural lag between billing and write-off, the impact was evident, particularly in 2002. The fiscal year 2002 $6,058,897 net-write off was a record high, and the impact of high gas prices continued for the next couple of years. In addition, fiscal year 2003 was the first year since 1996 that was measurably colder than normal and gas costs remained high, which also contributed to higher than normal net-write off for fiscal years 2003 and 2004.

As a result of these negative trends, Citizens Gas initiated process improvements starting in fiscal year 2003, which have impacted the level of net write-offs, and the extraordinarily high write-offs from 2002 to 2004 provided a much larger pool of written off accounts available for recovery to offset current write-offs.

Q. **HOW WILL RECOVERY OF NET WRITE-OFF GAS COST THROUGH THE GCA MECHANISM BENEFIT THE UTILITY AND ITS CUSTOMERS?**

A. Because the gas cost component of net write-offs will be recovered through the GCA at a fixed net write-off ratio of 0.8%, and the margin component will continue to be recovered through base rates, Citizens Gas will remain at risk for the margin component and for the level of the actual net write-off ratio. However, recovering the gas cost component of net write-offs through the GCA will allow Citizens Gas' net write-off recovery to fluctuate with natural gas prices, which are volatile and beyond the Utility's reasonable control. The test year and pro forma net write-off costs reflect current high natural gas prices. In the event natural gas prices drop and potentially become less volatile in the future, customers will benefit from lower GCA rates. On the other hand, if natural gas prices continue to rise, or other factors are introduced that result in additional net write-offs, the GCA treatment of net write-off gas costs will ensure Citizens Gas will not be financially harmed by its inability to recover gas costs.

Q. **HAS NET WRITE-OFF GAS COST RECOVERY VIA THE GCA MECHANISM BEEN APPROVED FOR OTHER INDIANA GAS UTILITIES?**

A. Yes. In Vectren North's most recent gas rate case, Cause No. 43298, the Commission approved a settlement agreement between Vectren North and the OUCC. Vectren South also reached an agreement with the OUCC in its most recent gas rate case, Cause No. 43112, to recover its gas cost component of net write-offs through its GCA mechanism. Citizens Gas has modeled its proposed net write-off gas cost recovery proposal after the mechanism agreed to in those rate cases and approved by the Commission in its August 1, 2007 and February 13, 2008 Orders, respectively.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO CITIZENS GAS' NET WRITE-OFFS AND THEIR RECOVERY?

A. Natural gas prices, weather, unemployment rates, and number of accounts written off are chiefly outside the control of Citizens Gas, are not predictable and may fluctuate for any number of reasons. Net write-offs are subject to the vagaries of the natural gas market. When net write-offs (which in large part are made up of the cost of gas) are significantly higher than the expense authorized for recovery in base rates, Citizens Gas is unable to recover its actual cost of gas as permitted under IC 8-1-2-42(g). In my opinion, the proposed net write-off gas cost recovery via the GCA mechanism will eliminate a significant financial risk for both Citizens Gas and its customers, and it will better align the Utility's actual net write-offs with the revenues required to cover that expense. Given the recent trends in the natural gas industry with respect to commodity prices, the proposed mechanism is a more appropriate method of dealing with this particular revenue requirement than the traditional method of using a test year or normalized amount for bad debt expense. Because net write-offs no longer can be predicted with a significant degree of certainty, the traditional ratemaking method has the potential to significantly harm the Utility financially. Alternatively, in the event the natural gas market stabilizes and gas prices drop, the traditional ratemaking method would cause the Utility to recover from customers net write-offs in excess of the net write-offs it actually experiences, as was the case in 2007.

Q. IS APPROVAL OF PETITIONER'S NET WRITE-OFF GAS COST RECOVERY PROPOSAL AS AN ALTERNATIVE REGULATORY PLAN REQUIRED FOR THE COMMISSION TO ALLOW CITIZENS TO IMPLEMENT ITS PROPOSAL?

A. I believe including the gas cost component of net write-offs in the GCA mechanism is already permitted by the GCA statute given that this approach has been approved for use by other gas utilities. However, to the extent the proposal would require Commission approval under the terms of IC 8-1-2.5-6 as an alternative regulatory practice, procedure, mechanism, or plan, Citizens Gas has requested that the Commission provide any required approval in this proceeding.

Q. HAVE YOU PREPARED A SET OF GCA SCHEDULES TO ILLUSTRATE HOW THE GAS COST COMPONENT OF NET WRITE-OFFS WILL BE PROJECTED AND RECONCILED IN THE GCA?

A. Yes. Those GCA schedules are contained in Petitioner's Exhibit LSP-6.

Q. PLEASE DESCRIBE THE NET WRITE-OFF GAS COST RECOVERY METHODOLOGY ILLUSTRATED IN PETITIONER'S EXHIBIT LSP-6.

A. The net write-off gas cost recovery methodology illustrated in Petitioner's Exhibit LSP-6 works as follows:

1. Net write-off gas costs will be estimated on Schedule 1, page 1, line 10a. The fixed net write-off ratio of 0.8% will be multiplied by the projected total gas costs, inclusive of unaccounted for gas ("UFAG") costs, for each month. On new Schedule 1C, the net write-off gas cost expense will be allocated to customer classes D1 through D4 according to the allocation factors listed on line 1. The allocation factors were determined by Petitioner's witness Craig A. Jones in conjunction with his cost of service study, and represent the net write-offs experienced by customer class during the test year. On line 4, the monthly estimated net write-off gas costs by class will be divided by projected sales volumes for each class for each month in the GCA quarter, yielding the net write-off gas cost component (in dollars per dekatherm) of the GCA rates. The net write-off gas cost component on Schedule 1C, line 4 is then carried over to Schedule 1, page 2, line 23a for inclusion in the Gas Supply Charge to be recovered through the GCA, which subsequently is adjusted to include Indiana Utility Receipts Tax.

2. New Schedule 12C will be filed in each GCA to determine the net write-off gas cost recovery variance. Actual net write-off gas cost recoveries will be calculated on line 3, by multiplying the actual retail sales volumes from Schedule 6 by the applicable net write-off gas cost component of the GCA rates which were in effect during the reconciliation period (two GCAs prior).

Actual recoverable net write-off gas costs then will be determined on line 5, by multiplying the actual recoverable gas costs from Schedule 6, page 1, column I, line 10 by the fixed ratio of 0.8%.

3. The total net write-off gas costs recovered (Schedule 12C, line 3) will be compared to the net write-off gas costs recoverable (line 5) to determine the net write-off gas cost recovery variance to be allocated to subsequent GCAs on Schedule 12B, line 3a. If recoverable costs are less than actual recoveries, the difference will be refunded to customers. Conversely, if recoverable costs are greater than actual recoveries, the difference will be recovered from customers.

4. In order to keep the net write-off recovery from being eliminated in the calculation of the Gas Cost Variance on Schedule 6, page 1, line 12a has been added to remove from the "gas costs recovered to be reconciled with actual cost of gas incurred" the net write-off recovered, as determined on Schedule 12C, line 3.

ALTERNATIVE TO MAIN EXTENSION RULE 170 IAC 5-1-27(F)

Q. PLEASE DESCRIBE CITIZENS GAS' PROPOSED ALTERNATIVE TO THE COMMISSION'S MAIN EXTENSION RULE.

A. As described more fully below, Citizens Gas is proposing to revise paragraph 3.6 of its Terms and Conditions of Service to provide for an alternate distribution main extension plan. In 170 IAC 5-1-27 (B), the Commission has provided that gas utilities are required to make "free of charge an extension necessary to give service when the estimated total revenue, for a period of three (3) years, from the prospective customers, is at least equal to the estimated cost of such extension." Citizens Gas proposes to substitute a five and one-half year non-gas cost revenue test in place of the Commission's three-year total revenue test.

Q. PLEASE DESCRIBE CITIZENS GAS' CURRENT MAIN EXTENSION DEPOSIT POLICY.

A. Currently, paragraph 3.6 of Citizens Gas' Terms and Conditions of Service refers to and effectively incorporates by reference, the Commission's Rules with respect to main extension deposits. 170 IAC 5-1-27(C) provides for what happens in the event that the cost of the main extension exceeds the costs limits set forth in 170 IAC 5-1-27(B). For example, 170 IAC 5-1-27(C)(3) provides that a gas utility must refund to the initial main extension applicants an amount equal to three (3) times the estimated annual revenue from new customers, less the cost to extend service to such new customers.

Q. IN WHAT WAY DOES CITIZENS GAS TAKE ISSUE WITH THE THREE-YEAR TOTAL REVENUE TEST IN 170 IAC 5-1-27(B)?

A. The use of total revenue to calculate the main extension credit has become, and is, increasingly unfair to Citizens Gas and to our current customers. The total revenue

Citizens Gas receives includes recovery of costs other than gas distribution-related costs, or margin, (i.e., pass through gas costs that the utility recovers on a dollar for dollar basis through the quarterly GCA process). Wholesale gas prices have been very high and volatile in recent history. To include this increasingly high and volatile pass through cost in prospective customer revenues to determine whether that new customer actually will generate enough margin revenue for Citizens Gas to recover its authorized non-gas revenue requirements, is both flawed and increasingly unworkable.

Q. **PLEASE ILLUSTRATE HOW THE THREE-YEAR TOTAL REVENUE TEST IS FLAWED.**

A. Petitioner's Exhibit LSP-7, illustrates how the three-year total revenue test results in an unreasonable period of time over which Citizens Gas is able to earn a return of its investment to extend the gas facility. The exhibit illustrates, during 1992, 1999, and 2007, the number of new customers that would be required in order for the average main extension to a new residential subdivision to qualify for the extension without deposit, utilizing the three-year total revenue test, and how that number has decreased significantly during that period of time as a result of high and volatile gas costs. The exhibit goes on to determine how many customers would be required in order for Citizens Gas to earn a return of the investment the three-year revenue test requires it to make. That number of customers has not changed substantially during the illustrated period of time. Then, Petitioner's Exhibit LSP-7, determines the number of new customers necessary for the average main extension to a new residential subdivision to qualify for the extension without a deposit, utilizing Citizens Gas' proposed five and one-half year non-gas cost revenue test, which also is the number of customers required for Citizens Gas to earn a return of its investment, and would not have changed in any significant way during the same illustrated period of time.

Q. **PLEASE EXPLAIN THE IMPACT OF THE THREE-YEAR TOTAL REVENUE TEST ON CITIZENS GAS' ABILITY TO EARN A RETURN OF ITS INVESTMENT.**

A. Petitioner's Exhibit LSP-7, line 6 indicates the number of customers required to qualify for a deposit-less main extension, and shows that in 1992 and 1999 the number of customers required would have been 12 and 11, respectively. While in 2007, only seven customers would have been required, representing an approximate 40% drop in the number of customers necessary to qualify for a main extension. However, during the same three years, it would have taken 23 customers in 1992 and 1999, and 21 customers in 2007 for Citizens Gas to earn a return of its investment. That amounts to three times as many customers for Citizens Gas to earn a return of its investment than the number of customers it would be required to serve pursuant to the three-year revenue test.

Q. IS USING TOTAL REVENUES, INCLUDING HIGH AND VOLATILE GAS PRICES, TO DETERMINE GAS MAIN EXTENSION CREDIT FOR NEW CUSTOMERS FAIR TO CITIZENS GAS OR ITS EXISTING CUSTOMERS?

A. No. Petitioner's Exhibit LSP-7 shows that the cost of gas increased moderately by 13.51% from 1992 to 1999 when compared to the 134% increase between 1999 and 2007. Concurrently, the non-gas costs remained unchanged between 1992 and 1999, and only increased by 15.81% between 1999 and 2007. The increase in the cost of gas has exponentially outpaced the increase in the non-gas costs. Therefore, the three-year total revenue test no longer is a valid methodology to determine the reasonable period and mechanism that Citizens Gas should use for main extension return of investment calculations. The total revenue formula can lead to an intergenerational inequity between current and future customers.

As previously illustrated, under the three-year total revenue test, Citizens Gas could be required to divert cash flow to pay for facility extensions that hold no promise of yielding any return for many years to come. The cash flow that is so diverted could otherwise be used to pay for necessary capital improvements, operating expenses and/or delay the need for and diminish the level of subsequent rate relief. Because the three-year total revenue test includes high and volatile gas costs (which do not contribute to margin recovery), the total revenue test may not result in a margin to Citizens Gas sufficient to pay the associated costs for the facility extension within a reasonable timeframe. In addition, the total revenue formula is inconsistent with the regulatory principle of cost causation. The result is that Citizens Gas and current customers could end up subsidizing new customers, with no accurate price signals sent as to the actual cost of new customer extensions. Moreover, given gas price volatility, new customers also could be treated differently. To the extent the revenue formula swings due to gas costs spikes and declines, the timing of the customer's request for an extension could impact the amount of the required deposit.

Q. HOW DOES CITIZENS GAS PROPOSE TO REMEDY THIS SITUATION?

A. The Commission's Rules at 170 IAC 5-1-27(F) allow a gas utility to request variation and alternatives from the extension rule. As reflected in Petitioner's Exhibits CAJ-12 and CAJ-13, Citizens Gas' revision to paragraph 3.6 of its Terms and Conditions of Service proposes a variance from the Commission's rule. Citizens Gas proposes that the three-year total revenue test be modified to a five and one-half year non-gas cost revenue test, which would exclude gas costs recovered through the quarterly GCA mechanism. This change should allow Citizens Gas the opportunity to recover the expenses it incurs to extend such facility within a more reasonable period of time and prevent the subsidization of new customers by current customers.

Q. DOES THAT CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, at this time.

VERIFICATION

STATE OF INDIANA)
) ss:
COUNTY OF MARION)

The undersigned, LaTona S. Prentice, under penalties of perjury and being first duly sworn on her oath, says that she is Executive Director of Regulatory Affairs of Citizens Gas & Coke Utility; that she caused to be prepared and read the foregoing Direct Testimony; and that the representations set forth therein are true and correct to the best of her knowledge, information and belief.

LaTona S. Prentice

By: LaTona S. Prentice
Executive Director of Regulatory Affairs
Citizens Gas & Coke Utility

Subscribed and sworn to before me, a Notary Public, this 17th day of March, 2008.

Ann Dunnavent
Signature

Ann Dunnavent
Printed Name

NOTARY PUBLIC SEAL INDIANA

My Commission Expires: 08/11/08

My County of Residence: Hancock

CITIZENS GAS & COKE UTILITY
Index of Exhibit LSP-1

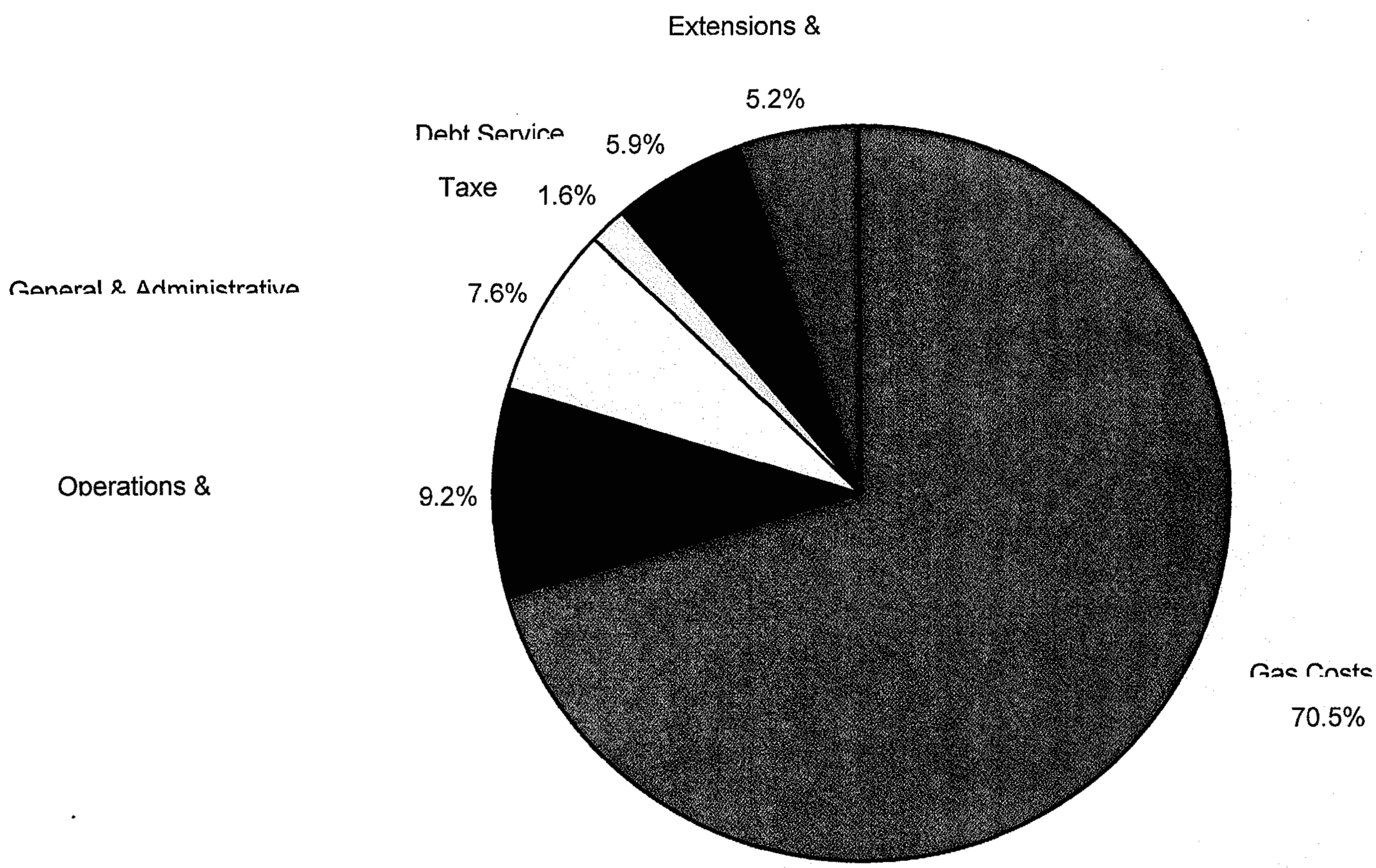
CITIZENS GAS & COKE UTILITY
Summary of Pro Forma Revenue Requirement

Line No.		A Actual per Books	B Pro Forma Adjustments Increase (Decrease)	C Pro forma Results Based on Current Rates	D Pro Forma Adjustments Increase (Decrease)	E Pro forma Results Based on Proposed Rates	F Reference
	Operating Revenues						
1	Test year revenues	$419,270,950					
2	Normal weather		19,889,472				page 5
3	Customer numbers		(5,592,885)				page 6
4	Change in average unbilled		(862,492)				page 7
5	Decoupling & NTA		316,323				page 7
6	*Correction Factor*		(765)				page 7
7	AMR		52,928				page 7
8	Storage True-up		(12,871)				page 7
9	Demand		(353,245)				page 7
10	Eliminate Rate Classes		(2,553)				page 7
11	Change in average customer charge		416,919				page 8
12	Change in gas price		13,078,840				page 8
13	Delivery rate		1,633,500				page 8
14	Rate 30 revenue		(1,707,887)				page 10
15	Miscellaneous revenue		(2,733,350)				page 10
16	Revenue Requirement Increase				$19,695,023		
17	Total Operating Revenues	$419,270,950	$24,121,934	$443,392,884	$19,695,023	$463,087,907	
	Gas Cost						
18	Test year gas costs	$299,826,241					
19	*Normal weather*		16,841,522				page 5
20	Customer numbers		(4,947,281)				page 6
21	Miscellaneous		(302,128)				page 7
22	Change in gas price		13,078,840				page
23	Company use gas from O & M and G & A		2,111,775				page 11 &
24	Total Gas Costs	$299,826,241	$26,782,728	$326,608,969	$0	$326,608,969	
25	**Gross Margin**	$119,444,709	($2,660,794)	$116,783,915	$19,695,023	$136,478,938	
	Operations & Maintenance						
26	Test year operations & maintenance	$40,938,560					
27	Company use gas to GCA		(2,069,297)				page 11
28	Price Volatility Mitigation		84,783				page 11
29	Insurance costs		35,637				page 11
30	Energy efficiency		433,588				page 11
31	Pension - Gas		(191,792)				page 12
32	Payroll - Gas		3,118,258				page 14
33	Employee benefits - Gas		(249,340)				page 15
34	Capitalized Credits - Gas		209,455				page 16
35	*Payroll related taxes - Gas*		181,184				page 20
36	Total Operations & Maintenance	$40,938,560	$1,552,477	$42,491,037	$0	$42,491,037	

CITIZENS GAS & COKE UTILITY
Summary of Pro Forma Revenue Requirement

Line No.		A Actual per Books	B Pro Forma Adjustments Increase (Decrease)	C Pro forma Results Based on Current Rates	D Pro Forma Adjustments Increase (Decrease)	E Pro forma Results Based on Proposed Rates	F Reference
	General & Administrative Expense						
37	Test year general & administrative expense	$35,092,225		$36,524,856			
38	Pension - CSS		(1,259,269)				page 12
39	Net Write-Off Non-Gas Cost		(2,092,891)		157,560		page 13 & 23
40	Payroll - CSS		4,883,673				page 14
41	Employee benefits - CSS		305,094				page 15
42	Capitalized Credits - CSS		9,364				page 16
43	Amortized FAS106		(451,032)				page 17
44	Company use gas to GCA		(42,478)				page 18
45	Insurance cost - corporate		96,867				page 18
46	General Office Facilities Maintenance Normalization		(695,011)				page 18
47	Manufacturing closure		502,030				page 18
48	Amortized regulatory expense		(146,942)				page 18
49	Adjust Depreciation		(1,151,864)				page 18
50	Payroll taxes - CSS		215,821				page 20
51	Total General & Adminstrative Expense	$35,092,225	$173,362	$35,265,587	$157,560	$35,423,147	
	Depreciation & Amortization						
52	Test year depreciation & amortization	$18,014,086					
53	Test year CSS depreciation		1,151,864				page 19
54	Increase depreciation		362,383				page 19
55	Pro forma Depreciation & Amortization	$18,014,086	$1,514,247	$19,528,333	$0	$19,528,333	
	Taxes						
56	Test year taxes	$11,158,097					
57	Pro forma change in IURT		(4,000,852)		275,730		page 21 & 24
58	Pro forma Taxes	$11,158,097	($4,000,852)	$7,157,245	$275,730	$7,432,975	
59	**Operating Income**	$14,241,741	($1,900,027)	$12,341,714	$19,261,732	$31,603,446	
	Other Funds Requirements						
60	Long-term interest and principal		$26,577,715	$26,577,715		$26,577,715	JRB-3
61	Other Interest		2,920,681	2,920,681		$2,920,681	JRB-3
62	Interest income		(2,361,245)	(2,361,245)		($2,361,245)	JRB-5
63	Debt Service		$27,137,151	$27,137,151	$0	$27,137,151	
64	Extensions and Replacements		$ 23,994,628	$23,994,628	$0	$23,994,628	CHB-1
	Cash Requirement Offsets						
65	Depreciation & Amortization			($19,528,333)	$0	($19,528,333)	
66	Pro forma Revenue Requirement increase before IURT increase			$19,261,732	$19,261,732	$0	

CITIZENS GAS & COKE UTILITY
PRO FORMA REVENUE REQUIREMENTS



CITIZENS GAS & COKE UTILITY
Test Year and Pro Forma Customers, Sales and Revenues

			A	B	C	D	E	F
			Test Year			Pro Forma		
Line No			Customers 1/	Therms	Revenue	Customers 1/	Therms	Revenue
1	Residential Domestic		3,731	1,163,810	$ 1,531,895	3,731	1,185,021	$ 1,722,521
2	Residential Heat		238,056	216,420,495	258,196,352	238,056	228,252,903	275,016,041
3	General Non-Heat		1,262	9,099,912	6,735,528	1,262	8,848,873	7,425,598
4	General Heat		21,910	130,097,265	120,857,201	21,946	138,149,436	129,436,694
5	Large Volume		215	98,215,463	21,011,353	161	50,149,842	21,366,558
6	NMGL		1	278	217	0	0	0
7	CNG - Compressed Natural Gas	2/	0	97,895	82,837	1	24,000	26,033
8	Interruptible	3/	0	52,493	2,739	0	0	0
9	High Load	4/	2	3,491,016	138,458	20	50,392,027	2,126,306
10	Rate 30		5	34,018,060	$ 2,431,158	5	23,011,986	$ 723,271
11	Total		265,182	492,656,687	$ 410,987,738	265,182	500,014,088	$ 437,843,022

1/ Average number of customers defined as number of meters
2/ There were 3 customers in July, August and September, 2007 for CNG
3/ There was only 1 customer in October, 2006
4/ There were 20 customers in September, 2007

CITIZENS GAS & COKE UTILITY
Normal Weather Adjustment

		A	B	C	D	E	F	G	H	I
Line No		HDD	Rate D1	Rate D2	Rate D3	Rate D4	Rate D5	Rate D7	Rate D9	Total
	Margin Adjustment:									
1	Adjusted Test Year Therms		1,136,750	215,028,975	8,664,202	131,055,408	50,149,842	24,000	50,392,027	456,451,204
2	Base Load Therms		496,266	39,568,332	6,213,903	35,956,675	32,093,695	24,000	33,555,132	147,908,003
3	Test Year Heat Load Therms	5,042	640,484	175,460,643	2,450,299	95,098,733	18,056,147	-	16,836,895	308,543,201
4	Normal Heat Load Therms	5,422	688,755	188,684,571	2,634,970	102,192,761		-	-	294,201,057
5	Normal Temp Therms Adjustment	380	48,271	13,223,928	184,671	7,094,028	-	-	-	
6	Tail Block Rate		$ 0.2771	$ 0.1716	$ 0.0763	$ 0.1059	$ -	$ -	$ -	$ -
7	Normal Temperature Margin Adjustment		$ 13,376	$ 2,269,226	$ 14,090	$ 751,258	$ -	$ -	$ -	$ 3,047,950
	Gas Cost Adjustment:									
8	*Normal Temp Adjustment*		48,271	13,223,928	184,671	7,094,028	-	-	-	20,550,898
9	Test Year Gas Cost per Therm		$ 0.80912	$ 0.86412	$ 0.62574	$ 0.74144	$ 0.14935	$ 0.64605	$ 0.00080	
10	Normal Temperature Gas Cost Adjustment		$ 39,057	$ 11,427,088	$ 115,556	$ 5,259,821	$ -	$ -	$ -	$ 16,841,522
11	**Revenue Adjustment**		$ 52,433	$ 13,696,314	$ 129,646	$ 6,011,079	$ -	$ -	$ -	$ 19,889,472

CITIZENS GAS & COKE UTILITY
Customer Number Adjustment

		A	B	C	D	E	F	G	H
Line No		Rate D1	Rate D2	Rate D3	Rate D4	Rate D5	Rate D7	Rate D9	Total
	Margin Adjustment:								
1	Net Change in Annual Meter/Customer Count	-	-	-	430	(639)	9	220	20
2	Test Year Avg. Customer Charge	$ 6.65	$ 10.00	$ 32.80	$ 35.42	$ 446.56	$ 70.00	$ 527.50	
3	Customer Charge Adjustment	$ -	$ -	$ -	$ 15,230	$ (285,349)	$ 630	$ 116,050	$ (153,439)
4	Non-Weather Related Change in Therms	-	-	-	2,337,043	(44,659,291)	(73,895)	46,901,011	4,504,868
5	Test Year Average Delivery Rate	$ -	$ -	$ -	$ 0.122210	$ 0.036888	$ 0.200572	$ 0.018858	
6	Non-Weather Related Adjustment	$ -	$ -	$ -	$ 285,609	$ (1,647,404)	$ (14,821)	$ 884,451	$ (492,165)
7	Total Customer Number Adjustment	$ -	$ -	$ -	$ 300,839	$ (1,932,753)	$ (14,191)	$ 1,000,501	$ (645,604)
	Gas Cost Adjustment:								
8	Change in Customer Therms	-	-	-	2,337,043	(44,659,291)	(73,895)	46,901,011	4,504,868
9	Test Year Gas Cost per Therm	$ 0.809122	$ 0.864122	$ 0.625740	$ 0.741444	$ 0.149350	$ 0.646049	$ 0.000800	
10	Customer Number Gas Cost Adjustment	$ -	$ -	$ -	$ 1,732,785	$ (6,669,849)	$ (47,740)	$ 37,523	$ (4,947,281)
11	**Revenue Adjustment**	$ -	$ -	$ -	$ 2,033,624	$ (8,602,602)	$ (61,931)	$ 1,038,024	$ (5,592,885)

CITIZENS GAS & COKE UTILITY
Other Adjustments

		A	B	C	D	E	F	G	H
Line No		Rate D1	Rate D2	Rate D3	Rate D4	Rate D5	Rate D7	Rate D9	Total
1	Pro Forma Unbilled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Test Year Unbilled	7,216	596,844	19,268	225,866	13,298	-	-	$ 862,492
3	*Unbilled Gas Revenue Adjustment*	$ (7,216)	$ (596,844)	$ (19,268)	$ (225,866)	$ (13,298)	$ -	$ -	$ (862,492)
4	Pro forma Decoupling & NTA	$61,050	$1,830,477	($28,558)	($471,637)	$ -	$ -	$ -	$1,391,332
5	Test Year Decoupling & NTA	$13,219	$754,449	$955	$306,386	$ -	$ -	$ -	$1,075,009
6	*Decoupling & NTA Adjustment*	$ 47,831	$ 1,076,028	$ (29,513)	$ (778,023)	$ -	$ -	$ -	$ 316,323
7	Pro forma Correction Factor Revenue	461	10,347	68	(19,992)	(33,088)	0	0	$ (42,204)
8	Test Year Correction Factor Revenue	501	7,469	81	(21,766)	(23,176)	0	(4,548)	$ (41,439)
9	Correction Factor Adjustment	$ (40)	$ 2,878	$ (13)	$ 1,774	$ (9,912)	$ -	$ 4,548	$ (765)
10	Pro forma AMR Revenue	0	0	3,840	14,592	58,368	0	20,736	$ 97,536
11	Test Year AMR Revenue	0	0	0	7,480	36,210	0	918	$ 44,608
12	AMR Adjustment	$ -	$ -	$ 3,840	$ 7,112	$ 22,158	$ -	$ 19,818	$ 52,928
13	Pro forma Storage True-up Revenue	0	0	0	0	0	0	0	$ -
14	Test Year Storage True-up Revenue	0	0	0	1,214	11,657	0	0	$ 12,871
15	Storage True-up Revenue Adjustment	$ -	$ -	$ -	$ (1,214)	$ (11,657)	$ -	$ -	$ (12,871)
16	Pro forma Demand Revenue	0	0	0	0	1,377,621	0	824,338	$ 2,201,959
17	Test Year Demand Revenue	0	0	0	0	2,480,432	0	74,772	$ 2,555,204
18	Demand Revenue Revenue Adjustment	$ -	$ -	$ -	$ -	$ (1,102,811)	$ -	$ 749,566	$ (353,245)
19	Eliminate Interruptible and NMGL Revenue								$ (2,553)
20	Miscellaneous Gas Cost Adjustment								$ (122,265)
21	Gas Cost Credit from Perry K								$ (179,863)
22	Total Miscellaneous Gas Cost Adj								$ (302,128)

CITIZENS GAS & COKE UTILITY
Change in Rate Adjustments

		A	B	C	D	E	F	G	H	I
Line No		**HDD**	**Rate D1**	**Rate D2**	**Rate D3**	**Rate D4**	**Rate D5**	**Rate D7**	**Rate D9**	**Total**
	Change in Delivery Rate:									
1	Pro Forma Average Delivery Rate		$ 0.277100	$ 0.203948	$ 0.097496	$ 0.124241	$ 0.033730	$ -	$ 0.022159	
2	Test Year Average Delivery Rate		$ 0.259675	$ 0.197861	$ 0.093966	$ 0.122210	$ 0.036888	$ -	$ 0.018858	
3	Change in Delivery Rate		$ 0.017425	$ 0.006088	$ 0.003530	$ 0.002031	$ (0.003158)	$ -	$ 0.003301	
4	Adjusted Test Year Therms		1,136,750	215,028,975	8,664,202	131,055,408	50,149,842	24,000	50,392,027	
5	Delivery Rate adjustment		$ 19,808	$ 1,308,990	$ 30,585	$ 266,180	$ (158,391)	$ -	$ 166,328	$ 1,633,500
	Change in Avg. Customer Charge:									
6	Proforma Meter Count		44,772	2,856,667	15,142	263,348	1,936	12	240	
7	Test Year Avg. Customer Charge		$ 6.65	$ 10.00	$ 32.80	$ 35.42	$ 446.56	$ 70.00	$ 527.50	
8	Proforma Avg. Customer Charge		$ 6.65	$ 10.00	$ 33.93	$ 36.51	$ 505.19	$ 70.00	$ 527.50	
9	Change in Avg. Customer Charge		$ (0.00)	$ -	$ 1.13	$ 1.09	$ 58.63	$ -	$ -	
10	Avg. Customer Charge Adjustment		$ (0)	$ -	$ 17,124	$ 286,278	$ 113,517	$ -	$ -	$ 416,919
	Change in Gas Price:									
12	Proforma Sales - Therms		1,185,021	228,252,903	8,848,873	138,149,436	50,149,842	24,000	50,392,027	
13	Test Year Gas Gas per Therm		$ 0.809122	$ 0.864122	$ 0.625740	$ 0.741444	$ 0.149350	$ 0.646049	$ 0.00080	
14	Proforma Gas Cost per Therm		$ 0.87478	$ 0.86996	$ 0.68872	$ 0.74853	$ 0.35111	$ 0.85967	$ 0.00099	
15	Change in Gas Cost per Therm		$ 0.06566	$ 0.00584	$ 0.06298	$ 0.00708	$ 0.20176	$ 0.21362	$ 0.00019	
16	Gas Price Adjustment		$ 77,809	$ 1,332,324	$ 557,268	$ 978,547	$ 10,118,201	$ 5,127	$ 9,564	$ 13,078,840

CITIZENS GAS & COKE UTILITY
Test Year Revenues, As Adjusted

Line No.		
1	Test year gas sales and transport revenue	$410,987,738
	Adjustments to test year results for:	
2	Test year Rate 30 revenues to other revenues	(2,431,158)
3	Adjusted test year gas sales and transportation revenue	$408,556,580

CITIZENS GAS & COKE UTILITY
Computation of Pro forma Other Revenues

Line No.		
1	Test year other revenue	$8,283,212
2	Test year Rate 30 revenue from gas revenues	2,431,158
3	Adjusted test year other revenue	$10,714,370
4	Pro forma decrease to Miscellaneous Gas Sales Revenues	(102,272)
5	Pro forma decrease to miscellaneous revenues	(55,208)
6	Pro forma decrease to other gas revenues	(2,575,870)
7	Pro forma decrease to Rate 30 revenues	(1,707,887)
8	Pro forma other revenue	$6,273,133

CITIZENS GAS & COKE UTILITY
Computation of Pro Forma Operations and Maintenance Expense

Line No.		
1	Test year operations and maintenance expense	$40,938,560
2	Adjustment for Company Use gas to GCA	($2,069,297)
3	Adjustment for price volatility mitigation costs	84,783
4	Adjustment for insurance costs	35,637
5	Adjustment for energy efficiency	433,588
6	Pro forma operations and maintenance expense	$39,423,271

CITIZENS GAS & COKE UTILITY
Computation of Pro Forma Pension Contribution

Line No.		
1	Test year pension expense - Gas	$1,123,556
2	Pension contribution adjustment - Gas	($191,792)
3	Pro forma pension contribution - Gas	$931,764
4	Test year pension expense - CSS	$1,840,492
5	Pension contribution adjustment - CSS	($1,259,269)
6	Pro forma pension contribution - CSS	$581,223
7	Total Pro forma pension contribution	$1,512,987

CITIZENS GAS & COKE UTILITY
Computation of Pro Forma Net Write-Off Non-Gas Cost

Line No.		
1	Test year provision for uncollectible expense	$ 3,010,000
2	Pro forma decrease to uncollectible expense	($2,092,891)
3	Total pro forma net write-off non-gas cost	$917,109

CITIZENS GAS & COKE UTILITY
Computation of Pro Forma Payroll Expense

		A	B	C
Line	Corp	Test Year	Pro forma	Adjustment
1	Total Regular Payroll	$11,157,733	$13,488,401	$2,330,668
2	Less : Capitalized payroll	202,991	276,954	73,963
3	Plus: overtime expense	135,432	163,749	28,317
4	Short Term Incentive Pay	2,036,612	2,037,665	1,053
5	Executive Incentive Plan Pay	(1,893,527)	555,029	2,448,556
6	Supplemental Pay	713,406	862,448	149,042
7	Total Payroll related expenses	$11,946,665	$16,830,338	$4,883,673
	Gas			
8	Total Regular Payroll	$14,881,579	$17,199,258	$2,317,679
9	Less : Capitalized payroll	1,341,075	965,314	(375,761)
10	Plus: overtime expense	2,698,585	3,118,913	420,329
11	Short Term Incentive Pay	1,409,921	1,356,291	(53,630)
12	Executive Incentive Plan Pay	65,505	69,176	3,671
13	Supplemental Pay	349,734	404,183	54,448
14	Total Payroll related expenses	$18,064,249	$21,182,507	$3,118,258

CITIZENS GAS & COKE UTILITY
Computation of Pro Forma Employee Benefits Expense

Line No.		Gas	CSS
1	Test year employee benefits expense	$5,913,081	$2,483,706
2	Pro forma disability & workman's compensation adjustment	(68,474)	25,942
3	Pro forma Citizens Gas 457 (B) Plan adjustment	(4,754)	(30,479)
4	Pro forma employee Thrift Plan adjustment	(23,804)	19,091
5	Insurance adjustment	$258,382	$272,497
6	Post retirement benefits adjustment	(689)	18,043
7	Post retirement benefits Customer Benefit Distribution adjustment	(410,000)	
8	Total pro forma employee benefits	$5,663,741	$2,788,800

CITIZENS GAS & COKE UTILITY
Computation of Pro Forma Capitalized Credit

Line No.		
1	Test Year Capitalized Credits - Gas	($559,757)
2	Capitalized Credit Adjustment - Gas	209,455
3	Pro Forma Credit - Gas	($350,302)
4	Test Year Capitalized Credits - CSS	($71,217)
5	Capitalized Credit Adjustment - CSS	9,364
6	Pro Forma Credit - CSS	($61,853)

CITIZENS GAS & COKE UTILITY
Amortization of FAS106 Expense

Line No.		
1	Test year Amortization of FAS106 expense	$451,032
2	Pro forma decrease to Amortization of FAS106 expense	(451,032)
3	Pro forma Amortization of FAS106 expense	$0

CITIZENS GAS & COKE UTILITY
Computation of Pro Forma Miscellaneous General & Administration Expense

Line No.		
1	Test year general & administrative expenses	$35,092,225
2	Test year CSS depreciation to Gas	($1,151,864)
3	Pro forma decrease for company use gas to GCA	($42,478)
4	Pro forma increase for insurance costs - corporate	96,867
5	Pro forma decrease to regulatory expense	(146,942)
6	Pro forma increase for general office facilities maintenance normalization	(695,011)
7	Pro forma increase for CSS cost for closure of manufacturing	502,030
8	Total pro forma general & administrative expense	$33,654,827

CITIZENS GAS & COKE UTILITY
Determination of Pro Forma Depreciation Expense

Line No.		
1	Test year depreciation expense - Gas	$ 18,014,087
2	Test year depreciation expense - CSS to Gas	1,151,864
3	Total test year depreciation	$19,165,951
4	Adjustment to depreciation	362,383
5	Pro forma depreciation expense	$ 19,528,334

CITIZENS GAS & COKE UTILITY
Determination of Pro Forma Payroll Tax Expenses

Line No.		Gas	CSS
1	Pro forma taxable payroll	$21,182,507	$16,830,338
2	Less: payroll exempt from social security tax	(436,183)	(3,264,351)
3	Payroll subject to FICA tax	$20,746,324	$13,565,987
4	Pro forma Social Security Tax at 6.2%	$1,286,272	$841,091
5	Pro forma SUTA Tax	35,114	23,102
6	Pro forma Medicare Tax at 1.45%	316,603	256,750
7	Pro forma payroll tax expenses	$1,637,989	$1,120,943
8	Test year payroll tax expenses	1,456,805	905,122
9	Pro forma increase to payroll tax expenses	$181,184	$215,821

CITIZENS GAS & COKE UTILITY
Determination of Pro Forma Indiana Utility Receipts Tax Expense

Line No.		
1	Pro forma non-gas cost revenue at present rates subject to IURT	$110,987,471
2	Indiana Utility Receipts Tax @1.40%	$1,553,825
3	Test year IURT expense	5,554,677
4	Pro forma IURT decrease	($4,000,852)

CITIZENS GAS & COKE UTILITY
Revenue Increase Adjusted
for IURT and Net Write-Off Non-Gas Cost

Line No.			
1	Total revenue increase		$19,261,732
2	One	1.0000	
3	Less: Indiana Utility Receipts Tax	0.014	
4	Less: Net Write Off - Non Gas	0.008	
5	Incremental Revenue Conversion Factor		0.9780
6	Increase in revenue requirement		$19,695,023

CITIZENS GAS & COKE UTILITY
Adjustment for Net Write-Off
Non-Gas Cost on Revenue Increase

Line No.		
1	Pro forma increase in revenue requirement	$19,695,023
2	Net Write-Off as % of revenue	0.80%
3	Pro forma increase in Net Write-Off Non-Gas Cost	$157,560

CITIZENS GAS & COKE UTILITY
Adjustment for Indiana Utility
Receipts Tax on Revenue Increase

Line No.		
1	Pro forma increase in revenue requirement	$19,695,023
2	Indiana Utility Receipts Tax rate	1.40%
3	Pro forma increase in Net Write-Off Non-Gas Cost	$275,730

Petitioner's Exhibit
LSP-2

BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

FILED

AUG 27 2002

INDIANA UTILITY
REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST D/B/A CITIZENS GAS & COKE UTILITY FOR (1) APPROVAL PURSUANT TO IC 8-1-2.5-1 ET SEQ. OF A NATURAL GAS ALTERNATIVE REGULATORY PLAN RESTRUCTURING CURRENT SERVICE OFFERINGS AND MODIFYING COMPLIANCE WITH IC 8-1.5-3-8, IC 8-1-2-42 AND REQUIREMENTS OF PRIOR COMMISSION ORDERS; (2) THE DECLINATION OF JURISDICTION NECESSARY TO IMPLEMENT SUCH A PLAN; AND (3) A FINDING THAT CERTAIN EMPLOYEE BENEFIT AND OTHER COSTS ARE ALLOWABLE FOR RATEMAKING PURPOSES AND THAT THE REQUESTED ALTERNATIVE REGULATORY PLAN WILL ALLOW SUCH COSTS TO BE RECOVERED IN RATES	)	**CAUSE NO. 41605**

STIPULATION AND SETTLEMENT AGREEMENT

The Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas & Coke Utility ("Citizens"), the Indiana Office of Utility Consumer Counselor ("OUCC"), the Citizens Gas Industrial Group, and each of its individual members (collectively, the "Parties"), solely for the purpose of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree that the following terms and conditions represent a modified alternative regulatory plan (including Exhibits A and B which will be filed prior to the hearing) and Exhibit C which is attached, and a fair, reasonable and just resolution of the issues listed in this Stipulation and Settlement Agreement ("Agreement"), subject to their incorporation into a non-appealable final order of the Indiana Utility Regulatory Commission ("Commission") without modification or further condition that may be unacceptable to any Party ("Final Order"). If the Commission does not approve this Agreement in its entirety, including Exhibits A, B, and C, the entire Agreement shall be null and void and deemed withdrawn, unless otherwise agreed to in writing by the Parties. Unless provided otherwise in the various sections of this Agreement, the terms of this Agreement will be implemented on the earlier of the first day of the sixth month following entry of the Final Order or the date following entry of the Final Order on which the

Commission accepts for filing as consistent with the Final Order the Gas Delivery, Gas Supply, And Administrative Services, Rates, Terms And Conditions, which will be filed as Exhibit A.

I. TERMS AND CONDITIONS OF AGREEMENT

A. **Affiliate Guidelines**. As part of its case-in-chief filed March 31, 2000 in this Cause, Citizens submitted a set of proposed Affiliate Guidelines as Petitioner's Exhibit CBL-5. All Parties to this proceeding are also Parties to the consolidated proceeding in Cause Nos. 37394GCA50S1, 37399GCA50S1 and 42233 ("GCA50"), which, inter alia, involves the contractual relationship with Citizens' affiliated gas marketer, ProLiance Energy, LLC. The Parties agree that the Affiliate Guidelines agreed to in GCA50 will apply to Citizens and supersede any need to agree upon Affiliate Guidelines in this Cause.

B. **Customer Benefit Tracker**. Citizens will establish a Customer Benefit Tracker ("CBT") as an integral part of the settlement of this Cause for the purposes of (i) distributing to its customers available funds from its unregulated businesses and affiliates or subsidiaries, and (ii) providing a means for Citizens potentially to "recover in rates" through a CBT credit mechanism certain FAS106 and FAS71 costs incurred by Citizens and agreed to by the Parties. The CBT will have the following components:

(1) The CBT and all of its terms and conditions are conditioned upon Commission approval and implementation pursuant to a Final Order;

(2) Citizens will file on or before November 30, 2002, and November 30 of each year thereafter, an annual CBT using the Commission's "30-day filing" procedures to be effective each January 1;

(3) Each CBT filing will show the amount of available funds Citizens received during the preceding fiscal year from unregulated businesses and affiliates or subsidiaries ("Available Funds"), and the net amount of those funds that Citizens' management and its Board of Directors by resolution, have determined will be provided for the benefit of gas customers pursuant to that annual CBT;

(4) At a minimum, the Available Funds for the CBT will be reduced to reflect Citizens' need to have "recovered in rates" through a credit mechanism for each annual CBT, the costs described in subparagraphs (a) and (b) below and subject to the following conditions:

(a) The Parties agree that Citizens' FAS106 transition obligation at March 31, 2002 is $5,208,014, which amount will be adjusted by the accruals added to this account through the date of the Final Order in this Cause. Citizens will recover through the CBT credit mechanism the agreed upon amount of its FAS106 transition obligation over the first twelve CBT filings. The FAS106 transition obligation will be "recovered in rates" by Citizens retaining 1/12 of the aforesaid annual FAS106 amount from the CBT Available Funds for each fiscal year. Citizens also will retain $410,000 each year (not limited by the twelve year amortization period) from the CBT Available Funds for Citizens' ongoing annual FAS106 costs.

(b) The Parties agree that Citizens' FAS71 regulatory asset for unbundling costs is $3,355,328 at March 31, 2002, which amount will be adjusted by the charges added to this account through the date of the Final Order in this Cause. This FAS71 regulatory asset will be split into equal halves, with one half of the amount to be "recovered in rates" (amortized over five years) through an annual reduction to the CBT. The remaining 50% of FAS71 costs will be dealt with as follows: Citizens will not recover one half of that amount (i.e. - 25% of the aforesaid total FAS71 costs) and the remaining 25% FAS71 amount will be recovered by Citizens, as a stipulated part of its rate case expenses in its next general rate case, to be amortized over three years.

(c) Citizens will not put into effect new general rates (except pursuant to an emergency petition filed under Ind. Code § 8-1-2-113) prior to September 30, 2003.

(d) As a condition precedent to any recovery, in whole or in part on an annual basis, of FAS106 and/or FAS71 costs as provided above, Citizens must pass through to its customers via the CBT an amount that is at least equal to the amount of Citizens recovery through the CBT of its aforesaid FAS106 and FAS71 costs. If there is not a complete match during any year, then Citizens shall not recover FAS106 or FAS71 costs through the CBT credit mechanism in excess of the amount made available to its customers that year through the CBT.

(e) Any amounts Citizens is obligated to provide to customers, or other entities, during 2002, 2003, 2004 and 2005, pursuant to the Settlement Agreement approved by the Commission in the GCA50 proceeding shall not count as a match to Citizens for any of its CBT obligations.

(f) Each annual CBT filing shall stand independently and there shall be no "banking" of FAS106 or FAS71 costs that were not recovered in a prior period, except for the remaining 25% of FAS71 costs which will be recovered in a general rate case in the manner described in paragraph (b) above.

(5) Citizens agrees to give the OUCC 30 days prior notice of the exact date on which it intends to file the annual CBT and to provide to the OUCC, on an informal basis, certain agreed to information and other information as requested, that is relevant to the CBT filing. Any relevant information that is deemed by Citizens or its affiliates to be confidential or proprietary will be provided to the OUCC subject to execution of a mutually acceptable confidentiality agreement;

(6) Citizens agrees to meet with the OUCC to discuss any issues it may have with respect to the mechanics or substance of the annual CBT filings; and

(7) If the OUCC and Citizens disagree as to the amount, nature, or adequacy of the information Citizens has provided to the OUCC in response to its requests and such disagreement is not resolved amicably within 45 days from the date of Citizens' notice of its intent to file the CBT, then the OUCC may ask the Commission to make the CBT filing the subject of a formal docketed Commission proceeding, with full rights to discovery under the Commission's Rules of Practice and Procedure. The OUCC, and any entity becoming a party to the docketed CBT proceeding, would be able to obtain information that is relevant to the CBT and may raise issues for the Commission's consideration. If the Commission grants a motion to compel discovery from Citizens related to the CBT filing and Citizens does not comply with that Commission order, then the moving party may seek enforcement of the Commission's order in a court of general jurisdiction in Marion County and pursue all available rights under Rule 28(F) of the Indiana Rules of Trial Procedure.

C. **<u>Interruptible Delivery Service (Gas Rate No. D8)</u>.** Citizens agrees to maintain an Interruptible Delivery Service Rate Class as part of the Gas Delivery, Gas Supply, and Administrative Services, Rates, Terms & Conditions, under the following conditions:

(1) Customers currently in the Interruptible Service Rate Class (Gas Rate No. 7) will be grandfathered into the Gas Rate No. D8 Rate Class for existing facilities, but no new customers, or new loads for existing Gas Rate No. 7 customers, will be added to the Gas Rate No. D8 Rate Class.

(2) Interruptible customers will be responsible for their own alternate fuel capability decisions, unless they are Human Needs Customers, which are required to have alternate fuel capability in accordance with the terms of Gas Rate No. D8.

(3) Citizens maintains the right to interrupt Interruptible Delivery Service customers under specified operating conditions to maintain system integrity. The following interruption provisions shall be included in Gas Rate No. D8:

> "Delivery service hereunder may be wholly or partially interrupted, when in the Utility's sole judgment such interruption or curtailment is necessary to maintain its system integrity."

(4) Automatic Meter Reading Service (AMR) will be required for Interruptible Delivery Service customers at the proposed rate of $34 per meter per month.

(5) Non-Performance charges apply if an Interruptible Delivery Service customer does not interrupt as ordered by Citizens.

D. **Nominations.**

(1) For a period of 30 days after the entry of a Final Order approving this Agreement, an End-Use Customer with annual usage greater than 1,000,000 Therms may provide written notice to Citizens that such End-Use Customer's transportation volumes will not be subject to Citizens' guidelines prescribing an allocation of nominations between the two interstate pipelines serving Citizens (the "50/50 Rule"). The initial maximum total system wide annual volume of gas eligible for nomination in this manner shall be 5 Bcf, and End-Use Customer eligibility will be determined on a first come-first served basis as described in this section. The initial aggregate volume of 5 Bcf will be determined according to End-Use Customer through-put during Citizens' most recently concluded fiscal year (10/1/00-9/30/01). Once the initial total of 5 Bcf has been reached (or the 30-day period has elapsed), the remaining End-Use Customers will be required to nominate based on the 50/50 Rule. After an End-Use Customer has provided written notice under this Section, the End-Use Customer and its existing accounts will not be subject to the 50/50 Rule so long as that rule is in effect, unless the End-Use Customer wishes to change its nomination practice and be subject to the 50/50 Rule under Section E(3) of this Agreement. The initial 5 Bcf total system wide gas volume will be used for sign-up purposes only. All volumes of gas subsequently nominated for an End-Use Customer whose transportation volumes are not subject to the 50/50 Rule, or any of the End-Use Customer's successors or assigns, will not be subject to the 50/50 Rule, regardless of whether total system wide annual volume of gas nominated by End-Use Customers not subject to the 50/50 Rule exceeds 5 Bcf.

(2) End-Use Customers participating in this program will be required to submit gas supply nominations in accordance with the following nominations procedures: 3rd Party Suppliers of Supplier Groups, and End-Use Customers acting as their own Supply Agent, will be required to submit an estimate of Daily Gas Supply Nominations to Citizens Gas at least five days prior to the beginning of each calendar month. These estimated nominations must include an entire month's worth of anticipated daily gas usage for each End-Use Customer within the 3rd Party Supplier's Supplier Groups and include estimates of Banking Volume Injections and Withdrawals (if applicable). Daily Gas Supply nominations are then required for each End-Use Customer. All nominations confirmed by the pipelines, will be entered into GMS for daily and monthly imbalance tracking.

(3) Pursuant to written notice to Citizens, an End-Use Customer that had previously provided written notice to Citizens under subparagraph E(1) above may change its nominations practice and thereafter satisfy the 50/50 Rule, in which case, Citizens, subject to the provisions of this subsection,

would open a 30-day sign-up period for those End-Use Customers who may be interested in nominating in percentages that vary from the 50/50 Rule. The volumes that become available in this manner also will be allocated to End-Use Customers on a first come-first served basis. Except for the load growth allowed in section D(1) above, the maximum allowable volume set forth in subsection D(1) (5 Bcf) shall be applicable for determining additional sign-up.

(4) The remainder of the End-Use Customers transporting on Citizens' system must make their nominations/deliveries on each pipeline serving Citizens' system consistent with the 50/50 Rule. 3rd Party Suppliers may combine/net their deliveries to achieve daily nomination delivery requirements in satisfaction of the 50/50 Rule.

E. **Scope of Unbundling.** The Parties agree that Citizens' rates and charges for the residential class (Rates 1 and 2) shall not be unbundled at this time. The Parties further agree to meet in the future at an appropriate date to discuss the timing and terms upon which Citizens might offer unbundling to its residential customers. The Parties further agree that this Agreement and the unbundling of gas rates shall apply to End-Use Customers with annual usage of 5,000 Dth or greater. The Parties further agree that unbundling for the remainder of End-Use Customers served under Gas Rate Nos. D3, D4, and D8 shall be phased in within two years following entry of a Final Order. The Gas Rates implementing the terms of this Agreement will be included as part of Exhibit A. A summary of rates and charges for End-Use Customers electing Basic Delivery Service under Gas Rates D3, D4, D5 and D8 and their 3rd Party Suppliers is attached hereto as Exhibit C.

F. **Opt-Out of Banking Service Provision.** Basic Delivery Service Customers with annual consumption in excess of 100,000 Dth may opt-out of Banking Service on an annual basis in accordance with the procedures described in this section of the Agreement and in the Initial Provisions For Opting-Out of Banking, set forth in Exhibit B.

An End-Use Customer must sign an agreement with Citizens to verify its intent to do without (or "opt-out" of) Banking Service for the elected 12-month period.

Any End-Use Customer desiring to resubscribe to Banking Service may do so, but only if sufficient capacity either exists, or can be procured by Citizens. Any costs that are the direct result of the customer returning to Banking Service, including but not limited to pipeline capacity costs and costs for storage services incurred by Citizens to return the End-Use Customer to Banking Service, will be directly charged to the returning End-Use Customer.

The initial notification of the election to opt-out of Banking Service must occur within 30 days of entry of a Final Order approving the Agreement in this Cause, and such election to opt-out of Banking Service shall be limited to the first 6 End-Use Customers or a period of 30 days, whichever comes first. That election request shall become effective on the first day of the month in which Citizens' processes are in place allowing the opt-out election to be implemented. In no case will the opt-out of Banking Service option become effective later than 60 days subsequent to the entry of a Final Order. The initial opt-out of Banking Service provision will remain effective through the effective date of the Gas Delivery, Gas Supply, And Administrative Services Rates, Terms and Conditions implementing the modified unbundling provisions of Cause No. 41605.

After an End-Use Customer has provided written notice under the section, the End-Use Customer will continue as an opt-out customer unless that customer wishes to change and does so in accordance with the provisions of this section. Subject to the previous sentence, subsequent to the initial opt-out period, beginning in February, 2004, to the extent not otherwise limited by this section, End-Use Customers will notify Citizens that they are electing to opt-out of Banking Service during the month of February ("Election Period") of each year. The election will become effective starting April 1 of that same year and remain effective through March 31, of the following year. Confirmation of the election will be returned to the End-Use Customer during the month of March immediately following the Election Period.

The throughput rate otherwise applicable to End-Use Customers who have opted-out will be reduced by $0.08 / Dth of throughput. Citizens may make available Incremental Banking Volumes to End-Use Customers under Gas Rate No. A9 and its Terms and Conditions of Service.

In accordance with the provisions of Section J of this Agreement, Citizens may request that the opt-out of Banking Service provisions be reconsidered or reopened by the Commission, if Citizens discovers that allowing customers to opt-out of Banking Service has resulted in costs being shifted to other customers or being stranded, in an amount exceeding $350,000 a year. The purpose of the reopener and reconsideration, with respect to Banking Service, will be to discuss modifying the opt-out provisions to keep the net annual cost of opting-out of Banking Service below $350,000, or otherwise to recover net costs above the $350,000 amount from the customers that are causing the costs. As provided for in Section J of this Agreement, if an acceptable modification to the Banking Service opt-out provisions cannot be developed that will reasonably limit Citizens' net exposure to less than $350,000 annually, the Parties agree to present the issue to the Commission for its determination.

G. **Mutuality**. The Parties agree that this Agreement has been filed for approval in a proceeding commenced under I.C.§ 8-1-2.5-1 et. seq. -- Alternative Utility Regulation. The Parties further agree that an important consideration for entry into this Agreement is equality of access to the Commission for purposes of enforcement, amendment, or termination of this Agreement or any of its provisions implementing an alternative regulatory plan. The Parties expressly agree that they will not object, on the basis of a lack of Commission jurisdiction, to any petition filed with the Commission by a Party with respect to this Agreement, any of its provisions, or any of the rates or terms and conditions of service attached thereto. The Parties agree that this Agreement, and the modified alternative regulatory plan agreed to herein, may not be amended, changed, or terminated except pursuant to a motion, petition or application of an express "reopener" provision, followed by notice, a hearing and final order of the Commission. The Parties further agree that no petition seeking an amendment, change, or termination of the Agreement, or the modified alternative regulatory plan, will be filed with the Commission by any Party without concurrently serving other Parties to this Agreement with written notice, and a copy, of such filing. The Parties further agree that the Commission should consider whether any proposed amendment, change or termination of the modified alternative regulatory plan is consistent with the public interest and should not apply the standard set forth in the last sentence of Ind. Code § 8-1-2.5-7.

H. **Monthly GCA.** Citizens and the OUCC have entered into a separate Stipulation and Settlement Agreement relating to this issue, which has been filed with the Commission for approval in Citizens' GCA75 proceeding.

I. **Term of Agreement**. Citizens agrees to continue the CBT portion of this Agreement set forth in Section B, and the modified alternative regulatory plan, for a period of at least twelve (12) years following January 1 of the first year the CBT is implemented. Thereafter, Citizens will continue to make annual CBT filings unless the Parties agree to modify or terminate the CBT. Other portions of the Agreement will continue unless and until modified or terminated by the Commission pursuant to Section G of this Agreement or pursuant to "reopener" provisions provided herein. The Parties agree that the modified alternative regulatory plan agreed to herein shall be subject to amendment, change or termination in Citizens next general rate case, except for the CBT credit mechanism which shall not be "reopened," amended, changed or terminated in a general rate case.

J. **Reopener** The Parties agree that, not later than 24 months after entry of a Final Order, the Parties will jointly review operational issues associated with the implementation of this Agreement. The review will include consideration of the Final Order (and any rules, regulations, requirements and costs resulting therefrom), including the 50/50 Rule, Daily Balancing, Banking Service and Supplier Access Requirements. The cost and effect on the operation of the Citizens system and on the development of a healthy competitive market will be evaluated. The Parties will cooperate with each other in timely providing relevant operational and cost information associated with implementation of this Agreement.

The Parties agree that they will work together to attempt to resolve any differences that may arise as a result of this review. In the event an agreement is not reached, any Party may present the issue(s) to the Commission for its determination(s).

K. **Presentation of this Agreement to the Commission.** The Parties shall support this Agreement before the Commission and request that the Commission accept and approve this Agreement without any changes or condition(s) unacceptable to any Party. The Parties further agree that testimony explaining and supporting this Agreement shall be prefiled with the Commission on or about August 27, 2002. The Parties agree that this Agreement shall be submitted to the Commission for approval on the condition that if the Commission fails to approve this Agreement in its entirety without any changes or condition(s) unacceptable to any Party, this Agreement and the supporting evidence shall be withdrawn, and the Commission shall conduct a prehearing conference, set a procedural schedule and continue with the litigation of this Cause at the point where it was suspended.

L. **Public Announcements**. The Parties shall agree on the form, wording and timing of any public/media announcement of this Agreement. All Parties may respond individually without prior approval of the other Parties to questions from the public or media, provided that such responses are consistent with such announcement and do not disparage any of the Parties.

M. **Effect and Use of Agreement.**

1. Except for the Affiliate Guidelines referred to in section A, the agreement referred to in section H, and Exhibits A, B and C which will be finalized and filed with the Commission prior to the hearing, there are no other agreements in existence between the Parties relating to the matters covered by this Agreement which in any way affect this Agreement.

2. The evidence which will be prefiled by the Parties in this Cause on or about August 27, 2002, and offered into evidence by agreement of the Parties, constitutes substantial evidence sufficient to support the Commission's finding that the Agreement is in the public interest pursuant to Ind. Code § 8-1-2.5-6(e) and provides an adequate evidentiary basis upon which the Commission can make any other findings of fact and conclusions of law necessary for the approval of the Agreement. If the Commission approves this Agreement, and Exhibits A, B and C, by Final Order, without any changes or condition(s) unacceptable to any Party, Citizens will accept in writing the resulting modified alternative regulatory plan within twenty (20) days after entry of the order.

3. The issuance of the Final Order shall terminate any further proceedings in this Cause other than those specifically delineated herein.

4. This Agreement shall not constitute nor be cited as precedent by any person or deemed an admission by any Party in any other proceeding except as necessary to enforce its terms before the Commission, or any tribunal or competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process and, except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Parties may take with respect to any or all of the issues resolved herein in any future regulatory or other proceeding.

5. The undersigned have represented and agreed that they are fully authorized to execute this Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby, subject to the agreement of the Parties on the provisions of Exhibits A, B and C.

6. The Parties shall not appeal the agreed Final Order to the extent such order materially implements the provisions of this Agreement and the Parties

shall not support any appeal of any such order by a person not a party to this Agreement.

7. The provisions of this Agreement shall be enforceable by any Party, in any tribunal of competent jurisdiction, including but not limited to the Commission.

8. The communications and discussions during the negotiations and conferences attended only by any or all of the Parties, their attorneys, and their consultants have been conducted on the explicit understanding that said communications and discussions are or relate to offers of settlement and therefore are privileged. All prior drafts of this Agreement also are or relate to offers of settlement and are therefore privileged.

9. The Parties shall not appeal or seek rehearing, reconsideration or a stay of any Final Order entered by the Commission approving the Agreement in its entirety without changes or condition(s) unacceptable to any Party (or related orders to the extent such orders are specifically implementing the provisions of this Agreement) and shall support this Agreement in the event of any appeal or a request for rehearing, reconsideration or a stay by any person not a Party hereto.

ACCEPTED AND AGREED this 27th day of August, 2002.

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

Anne E. Becker

By: Anne E. Becker

CITIZENS GAS INDUSTRIAL GROUP, and each of its individual members

J. F. Wickes, Jr.

By: John F. Wickes, Jr.

BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST, D/B/A CITIZENS GAS & COKE UTILITY

Michael B. Cracraft

By: Michael B. Cracraft

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EXHIBIT A

Gas Delivery, Gas Supply, and Administrative Services,

Rates, Terms and Conditions

(to be filed upon completion)

EXHIBIT B

Citizens Gas & Coke Utility

Initial Provisions for Opting-Out of Banking Service

EXHIBIT B

CITIZENS GAS & COKE UTILITY INITIAL PROVISIONS FOR OPTING-OUT OF BANKING SERVICE

The settlement of Cause No. 41605 provides a mechanism for End-Use Customers to opt-out of Banking Service. During the period between implementation of this initial opt-out provision and the effective date of the rates and charges and terms and conditions of service detailing the modified unbundling provisions of Cause No. 41605, the following conditions will apply:

- The availability of the opt-out provision will be on a first-come-first-served basis to End-Use Customers that use in excess of 100,000 Dth annually.
- The option will be limited to the first 6 End-Use Customers, or the expiration of 30 days following entry of the Final Order in Cause No. 41605, whichever is first.
- An End-Use Customer choosing this option may only elect 100% opt-out.
- The End-Use Customer must have daily metering capability, and agree to pay $34 per meter per month for Automated Meter Reading equipment.
- The End-Use Customer, its designated Supply Agent or its 3rd Party Supplier will be responsible for submitting Daily and intraday Gas Supply Nominations.
- The End-Use Customer, its designated Supply Agent or its 3rd Party Supplier will be responsible for adjusting Daily and intraday Gas Supply Nominations to keep usage within a 10% positive or negative imbalance for the current month.
- A credit of $0.08 per Dth of monthly throughput will be applied to the End-Use Customer's bill.
- The $0.08 per Dth credit will not be applied to consumption on specific days when the End-Use Customer has a +/- 10% or greater cumulative imbalance for three or more consecutive days. When a third consecutive day occurs where the cumulative imbalances are greater than +/-10%, the $0.08 per Dth credit will not apply to any consumption volumes on any day (including the first two days) until the cumulative imbalance is once again less than +/-10%. If the cumulative imbalance is reduced below +/-10% on or before the third consecutive day, the $0.08 per Dth credit will still apply to the usage on all three days, including the previous day(s) where the imbalance exceeded +/-10% (positive or negative). If any day's imbalance is reduced to below the +/-10% level, the $0.08 per Dth credit will apply to that day's consumption and the credit will continue to be applicable to each day's consumption unless and until three consecutive days occur where the cumulative imbalances are greater than +/-10%.
- Negative imbalances reflect situations where an End-Use Customer consumes a greater volume of gas in a Gas Day than is delivered on that End-Use Customer's behalf for that Gas Day.
- Positive imbalances reflect situations where an End-Use Customer consumes a lesser volume of gas in a Gas Day than is delivered on that End-Use Customer's behalf for that Gas Day.
- Any accumulated imbalance for a month will be carried over as the beginning imbalance for the subsequent month.
- Citizens Gas will notify the End-Use Customer any time the End-Use Customer's imbalance is in excess of +/-10%.
- The End-Use Customer will be responsible for submitting the name(s) and phone number(s) of the parties to be contacted in the event that a +/-10% or greater imbalance occurs.

- Citizens Gas will not contact the End-Use Customer on days where the cumulative imbalance is less than +/-10%

The foregoing provisions will expire upon the effective date of the rates and charges and Terms and Conditions of service implementing the unbundling provisions of Cause No. 41605. At that point the rates and services provided for in the appropriate tariffs, including the Basic Usage Balancing Service, will apply.

Table No. 1 shows how imbalances will be determined:

TABLE NO. 1

Day	Nom	Usage	Imbal	Cum Imb	%	> +/-10%	Credit/Dth
Prior month carryover				-800		no	$0.08
1	4,000	4,100	-100	-900	900/4,000=22.5%	yes	$0.08
2	4,000	3,800	+200	-700	700/8,000=8.75%	no	$0.08
3	4,000	4,300	-300	-1,000	1,000/12,000=8.3%	no	$0.08
4	4,000	4,600	-600	-1,600	1,600/16,000=10%	yes	$0.00
5	4,000	5,000	-1,000	-2,800	2,800/20,000=14%	yes	$0.00
6	4,000	4,300	-300	-2,900	2,900/24,000=12.08%	yes	$0.00
7	4,000	4,000	0	-2,900	2,900/30,000=9.67%	no	$0.08
Etc.							

EXHIBIT C

Summary of Rates and Charges

for Basic Service Customers

Exhibit C
Summary of Rates and Charges for Basic Service Customers

A. Rates and Charges For Basic Customers

1. Delivery Rates:
Citizens Gas' tiered delivery rates in Gas Rate No. D3, D4, D5, and D8..

2. Basic Usage Balancing Service:
   a) Under Non-OFO conditions:
      1) 0-15% band for net Daily Imbalances: no daily cash out, a monthly (netted) cash out under Gas Rate No. A2.
      2) 15%-30% band for net Daily Imbalances: daily cash out for daily imbalance amounts in excess of 15%under Gas Rate No. A3, at average of first of the month index prices of TGTC and PEPL, adjusted for appropriate fuel, transport & basis.
      3) Net Daily Imbalances greater than 30%: daily cash out for imbalance amounts greater than 30% under Gas Rate A4, at the average of first of the month index prices of TGTC and PEPL, adjusted for appropriate fuel, transport & basis, plus $1.50/decatherm for imbalance amounts greater than 30% in non-OFO conditions.
   b) Under OFO conditions, see Section B.

3. Cash Outs
If a daily cash out occurs, the imbalance volumes cashed out under the daily cash out provisions will be removed from any monthly cash out calculation. All imbalances not previously cashed out under the daily cash out provisions will be cashed out monthly according to Gas Rate No. A2.

4. Netting
For purposes of calculating Usage Imbalance charges or Basic Usage Imbalance charges, the monthly imbalances can be netted within a Supplier Group. At month end, for those days where daily imbalance charges are to be calculated and billed, Daily Imbalances for that day can be netted within the Supplier Group. Imbalance volumes used to calculate Daily Imbalance charges will not be included in, or netted against, the volumes used to calculate the monthly imbalance charge.

B. Operational Flow Orders ("OFOs")

1. Issuance of Economic OFOs
Citizens can issue an Economic OFO when Citizens, in its sole discretion, determines that such an OFO is necessary to protect its ability to provide reliable and adequate gas supply at reasonable cost because there is a significant and substantial price difference between the average of first of the month index prices of TGTC and PEPL, adjusted for appropriate fuel, transport & basis and the average of the daily index prices of TGTC and PEPL, adjusted for appropriate fuel, transport & basis.

2. Cash Out

a. Economic OFOs

In Económic OFO conditions, the cash out for any daily imbalances greater than 0% up to 30% will be done according to Gas Rate No. A3 at Citizens' WACOG index (see section B.2.c.). The cash out for any daily imbalances greater than 30% will be done under Gas Rate No. A4 at Citizens' WACOG index (see section B.2.c.), plus $2/decatherm.

b. Non-Economic OFOs

In Non-Economic OFO, interruption, or curtailment conditions, the daily cash out for any imbalances greater than 0% up to 15% will be done under Gas Rate No. A3 at Citizens' WACOG index (see section B.2.c.). The cash out for any daily imbalances greater than 15% will be done under Gas Rate No. A4 at Citizens' WACOG index (see section B.2.c.), plus $60/decatherm.

c. Citizens WACOG index

If the customer is buying gas, the customer will pay the Capacity cost shown on Rider B and the higher of:

1) the average of first-of-month-index prices of TGTC and PEPL, adjusted for appropriate fuel, transport & basis; or

2) Average of the daily indices of TGTC & PEPL, adjusted for appropriate fuel, transport & basis.

If the customer is selling gas, the customer will be reimbursed the lower of:

1) the average of first-of-month-index prices of TGTC and PEPL, adjusted for appropriate fuel, transport & basis; or

2) Average of the daily indices of TGTC & PEPL, adjusted for appropriate fuel, transport & basis.

C. **Waivers**

Pursuant to Gas Rate No. A4, in its reasonable discretion, on a case-by-case basis, the Utility may waive all or part of any Non-Performance Charge assessable to End-Use Customer, provided, however, that the waiver of such penalty shall be exercised on a non-discriminatory basis.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that on this 27th day of August, 2002, a copy of the Stipulation and Settlement Agreement in the above-captioned Cause was served by personal delivery or by United States mail, first-class, postage pre-paid upon the following:

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Attorney for Citizens Gas & Coke Utility

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Indianapolis, IN 46204-2030
317-636-5401

Petitioner's Exhibit
LSP-3

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST D/B/A CITIZENS GAS & COKE UTILITY FOR (1) APPROVAL PURSUANT TO IC 8-1-2.5-1 ET SEQ. OF A NATURAL GAS ALTERNATIVE REGULATORY PLAN RESTRUCTURING CURRENT SERVICE OFFERINGS AND MODIFYING COMPLIANCE WITH IC 8-1.5-3-8, IC 8-1-2-42 AND REQUIREMENTS OF PRIOR COMMISSION ORDERS; (2) THE DECLINATION OF JURISDICTION NECESSARY TO IMPLEMENT SUCH A PLAN; AND (3) A FINDING THAT CERTAIN EMPLOYEE BENEFIT AND OTHER COSTS ARE ALLOWABLE FOR RATEMAKING PURPOSES AND THAT THE REQUESTED ALTERNATIVE REGULATORY PLAN WILL ALLOW SUCH COSTS TO BE RECOVERED IN RATES	)	**CAUSE NO. 41605** **APPROVED:** DEC 11 2002

<u>BY THE COMMISSION</u>:
Judith G. Ripley, Commissioner
Abby R. Gray, Administrative Law Judge

On November 23, 1999, the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas & Coke Utility ("Citizens" or "Petitioner") filed its Petition seeking approval of an Alternative Regulatory Plan ("ARP") that would permit it to "unbundle" its costs and restructure service offerings. Specifically, Citizens proposed to "unbundle" or separate the Gas Supply Services customers receive (the procurement of gas supply at the wellhead and transportation to Citizens' city gate) from Delivery Services (the distribution of gas supply from Citizens' city gate to customer premises).

To the extent necessary to implement its ARP, Citizens requested that the Indiana Utility Regulatory Commission ("Commission") also decline to exercise a portion of its jurisdiction over Citizens. Citizens additionally asked the Commission to find that certain of its costs were allowable for ratemaking purposes, within the meaning of Statement of Financial Accounting Standard No. 106 ("SFAS 106"), and Statement of Financial Accounting Standard No. 71

("SFAS 71") and to permit these costs to be recovered in Citizens' rates through a credit to a proposed new Customer Benefit Tracker.

Citizens published notice of the filing of this proceeding pursuant to I.C. 8-1-2.5-6(d) of the Alternative Utility Regulation Act in the Indianapolis Star on December 7, 1999, and in The Daily Reporter (Hancock County), The Lebanon Reporter (Boone County) and The Hendricks County Flyer Weekend Edition (Hendricks County) on January 6, 2000, January 7, 2000 and January 6, 2000, respectively.

On December 29, 1999, a group of Citizens' large volume industrial customers, Citizens-Industrial Group ("CIG"), filed a Petition to Intervene in this proceeding. On January 5, 2000, the Citizens Action Coalition of Indiana, Inc. ("CAC") filed a Petition to Intervene.

Pursuant to public notice duly published as required by law, a Prehearing Conference was convened in Room E306 of the Indiana Government Center South at 302 West Washington Street in Indianapolis, Indiana on January 5, 2000. During the Prehearing Conference, the Petitions to Intervene filed on behalf of CIG and CAC were granted on the record. Citizens, the Office of Utility Consumer Counselor ("OUCC"), CIG and CAC appeared and participated at the Prehearing Conference. The Commission issued a Prehearing Conference Order in this Cause on January 12, 2000, setting forth the agreed-upon procedural schedule.

Citizens filed the Direct Testimony and Exhibits constituting its case-in-chief on March 31, 2000. Thereafter, the parties began settlement discussions in an attempt to resolve or limit the issues involved in this proceeding. The Commission held periodic Status Conferences to keep apprised of those settlement discussions.

On August 27, 2002, Citizens, the OUCC and CIG (collectively "Settling Parties") entered into, and filed with the Commission, a Stipulation and Settlement Agreement ("Settlement Agreement"). Citizens filed the Supplemental Testimony and Exhibits of Carey B. Lykins, Craig A. Jones and LaTona S. Prentice in support of the Settlement Agreement on September 9, 2002.

On September 23, 2002, the Commission conducted a technical conference, at which the Commission Staff asked questions of Citizens' witnesses related to certain provisions of the Settlement Agreement and Citizens' proposed Rates, Charges and Terms and Conditions of Service. As a result of the technical conference, Citizens agreed to make certain revisions to its filing to address questions raised by the Commission Staff. On September 27, 2002, Citizens submitted its Notice of Filing Certain Revisions to the Proposed Rates and Charges and Terms and Conditions of Service Pursuant to September 23, 2002 Technical Conference.

On October 1, 2002, pursuant to notice duly published as required by law, a public evidentiary hearing was commenced in Room E-306 of the Indiana Government Center South. Citizens, the OUCC, CIG and CAC appeared and participated at the evidentiary hearing. During the hearing, the Settlement Agreement, as well as Supplemental Testimony and Exhibits, were admitted into evidence without objection. Citizens' Notice of Filing Certain Revisions to the

Proposed Rates and Charges and Terms and Conditions of Service Pursuant to September 23, 2002 Technical Conference also was admitted into evidence without objection.

Based upon the applicable law and evidence of record, the Commission now finds:

1. **Commission Jurisdiction and Notice.** Proper legal notice of the hearing in this Cause was given as required by law. Moreover, legal notice of the filing of Citizens' Petition seeking approval of the ARP was published as required by I.C. 8-1-2.5-6(d). Citizens is a municipally owned gas utility subject to the Commission's jurisdiction under I.C. 8-1-11.1-1, and is an energy utility under I.C. 8-1-2.5-2. Therefore, the Commission has jurisdiction over the parties and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner is the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, doing business as Citizens Gas & Coke Utility. Petitioner's principal office is located at 2020 North Meridian Street, Indianapolis, Indiana. Petitioner owns, operates, manages, and controls plant and equipment within the State of Indiana used for the transmission, delivery, and furnishing of gas utility service to the public in the State of Indiana. Citizens provides gas service to approximately 262,000 customers in and around Marion County, Indiana.

3. **The Settlement Agreement and Modified ARP.**

(a) Citizens' "Unbundled" Rates and Charges. Exhibit A to the Settlement Agreement includes Gas Delivery, Gas Supply and Administrative Services Rates, and Terms and Conditions of Service. The agreed upon rates reflect the separation of Citizens' traditional gas service offerings into "Gas Supply" and "Gas Delivery" services.

(b) The Revised Terms and Conditions of Service and the Citizens Energy Select Program. Under the revised Terms and Conditions of Service, Citizens' customers served under its General Non-Heating, General Heating, Large Volume and Interruptible rate schedules, with an annual usage exceeding 50,000 Therms will become eligible to select a 3rd Party Supplier to provide their Gas Supply Service no later than the first day of the sixth month following the entry of the Final Order. The parties have agreed to meet in the future to discuss the timing and terms upon which Citizens might offer unbundling to its residential customers.

(c) The Customer Benefit Tracker. In Section B of the Settlement Agreement, the Settling Parties set forth the terms of the structure of Citizens' Customer Benefit Tracker ("CBT"). The CBT provides a mechanism by which available funds from Citizens' unregulated businesses and affiliates or subsidiaries, including Citizens By- Products, can be distributed to gas customers. A Customer Benefit Adjustment will be made to the per Therm delivery charge of Citizens' customers.

The CBT also provides a means for Citizens to recover in rates through a crediting mechanism certain SFAS 106, SFAS 71 and other costs incurred by Citizens.

Under the CBT, Citizens would add to the available pool of funds from the Manufacturing Division and Oil Division funds from its unregulated businesses and affiliates or subsidiaries that the Citizens Board of Directors periodically determines are not otherwise needed to service debt, pursue new business initiatives or to satisfy other internal financial requirements. Subject to the Commission's approval, Citizens will file on or before November 30, 2002, and November 30 of each year thereafter, an annual CBT using the Commission's "30-day filing" procedures. If the 30-day CBT filing is approved by the Commission, the CBT then would become effective the following January 1. Each CBT filing will show the amount of available funds Citizens received during the preceding year from unregulated businesses and affiliates or subsidiaries ("Available Funds"), and the net amount that the Board, by resolution, has determined will be provided through the CBT for the benefit of gas customers.

The Available Funds for each annual CBT will be reduced to reflect Citizens' need to have "recovered in rates" through a credit mechanism certain SFAS 106, SFAS 71 and other costs Citizens has and will continue to incur. The Settling Parties have agreed Citizens' SFAS 106 transition obligation at March 31, 2002 was $5,208,014, which amount will be adjusted by the accruals added to this account through the date of this Order. Citizens will recover through the CBT credit mechanism the agreed upon amount of its SFAS 106 transition obligation over the first twelve CBT filings. The SFAS 106 transition obligation will be "recovered in rates" by Citizens retaining 1/12 of the aforesaid annual SFAS 106 amount from the CBT Available Funds for each fiscal year. Citizens also will retain $410,000 each year (not limited by the twelve year amortization period) from the CBT for Citizens' ongoing annual SFAS 106 cost.

The Settling Parties also agreed that Citizens' SFAS 71 regulatory asset for unbundling costs was $3,355,328 at March 31, 2002, which amount will be adjusted by the charges added to this account through the date of this Order. This SFAS 71 regulatory asset will be split into equal halves, with one half of the amount to be "recovered in rates" (amortized over five years) through an annual reduction to the CBT. The remaining 50% of SFAS 71 costs will be dealt with as follows: Citizens will not recover one half of that amount (i.e., 25% of the aforesaid total FAS71 costs) and the remaining 25% SFAS 71 amount will be recovered by Citizens, as a stipulated part of its rate case expenses in its next general rate case, to be amortized over three years.

Thirty days prior to the filing of the CBT with the Commission, Citizens will provide information regarding the CBT filing to the OUCC and the Commission's Gas/Water/Sewer Division. Citizens has further agreed to meet annually with the OUCC and the Commission's Gas/Water/Sewer Division to discuss any issues they may have with respect to the proposed CBT filing. If Citizens and the OUCC disagree as to the amount, nature or adequacy of the information Citizens has provided, the OUCC may ask the Commission to make the CBT 30-day filing a formal docketed proceeding.

In order for Citizens to be able to recover through the CBT credit mechanism the identified SFAS 106 and SFAS 71 costs, it must pass through to its customers an amount that is at least equal to the amount of its recovery through the CBT of those costs. To the extent that Citizens does not completely match during any year the amount of the SFAS 106 or SFAS 71 costs through the CBT credit mechanism, then Citizens will not be able to recover such costs in excess of the amount made available to its customers that year through the CBT. In addition, the amounts which Citizens is obligated to provide to customers or other entities during 2002, 2003, 2004 and 2005 pursuant to the Settlement Agreement in Cause Nos. 37394-GCA50S1, 37399-GCA50S1 and 42233 ("GCA50"), approved by Order of the Commission on July 24, 2002, do not count as a match to Citizens for any of its CBT obligations. Finally, each annual CBT filing stands independently and there will be no "banking" of SFAS 106 and SFAS 71 costs that were not recovered in a prior period, except for certain SFAS 71 costs, which the Settling Parties have agreed will be recoverable in Citizens' next general rate case.

(d) Affiliate Guidelines. Under Section A of the Settlement Agreement, the Settling Parties agree that the affiliate guidelines approved by the Commission in the GCA50 proceeding supersede any need to agree upon affiliate guidelines in this Cause.

(e) Monthly Gas Cost Adjustment. Originally, Citizens also sought authority to modify its current Gas Cost Adjustment ("GCA") filing mechanism to use a monthly factor. In Cause No. 37399-GCA75, the Commission approved on an interim basis an agreement between Citizens and the OUCC under which Citizens will implement a Monthly Flex Mechanism. The Monthly Flex Mechanism allows Citizens to file monthly adjustments to the GCA factors approved in its quarterly filings and supercedes any need to agree on this issue in this Cause.

4. Discussion and Findings.

(a) Citizens' Unbundled Rates and Charges and Terms and Conditions of Service. Citizens commenced this Cause as an energy utility seeking approval of an ARP, pursuant to I.C. 8-1-2.5. Section 6(a) of the Alternative Utility Regulation ("AUR") Act authorizes the Commission to adopt alternative regulatory procedures, and establish rates and charges that are in the public interest, and enhance or maintain the value of the utility's energy services or properties. The alternative regulatory plans and practices authorized by the AUR Act include practices, procedures, and mechanisms focusing on the price, quality, reliability, and efficiency of the service. I.C. 8-1-2.5-6(a)(1). In addition, the Commission may establish rates based on market or average prices, price caps, index based prices, and prices that (a) use performance based rewards or penalties, and (b) are designed to promote efficiency in the rendering of retail energy service. I.C. 8-1-2.5-6(a)(2).

The Settling Parties have filed the Settlement Agreement seeking approval of their agreement as described in the Settlement Agreement and Exhibits. The Settlement Agreement includes as part of its terms and conditions a modified ARP and reflects many hours of negotiations at arms' length among the Settling Parties. In Section G of the Settlement Agreement, the Settling Parties agreed that equality of access to the Commission for enforcement, amendment or termination of the Settlement Agreement, and the modified alternative regulatory plan, was an important consideration. They further agreed that the modified alternative regulatory plan may not be amended, changed or terminated except pursuant to a motion, petition or application of an express "reopener" provision, followed by notice, a hearing and final order of the Commission, and further that the Commission should not apply the standard set forth in the last sentence of IC 8-1-2.5-7 in considering whether the proposed amendment, change or termination is in the public interest.

The Commission finds that the evidence submitted constitutes substantial, probative evidence sufficient to support the Settlement Agreement and the modified ARP included as part of its terms and conditions. Our approval of this Settlement Agreement includes the necessary approval of the ARP, as modified by the Settlement Agreement and to effectuate this Settlement Agreement's terms and conditions. We find that approval of the Settlement Agreement and modified ARP included as part of its terms and conditions is in the public interest, is reasonable and in conformance with all statutory requirements.

The Commission finds the Settlement Agreement was negotiated in good faith and at arm's length following full disclosure of relevant information. The OUCC was actively involved in all phases of the litigation and is in a good position to make an informed assessment as to the merits of the Settlement Agreement. The Commission finds that the Settlement Agreement is reasonable and in the public interest, and that it should be and hereby is approved in its entirety.

(b) Statement of Financial Accounting Standard No. 106. In the Petition, Citizens requested that the Commission approve its adoption of SFAS 106. SFAS 106, "Employers Accounting For Post-Retirement Benefits Other than Pensions," was issued by the Financial Accounting Standards Board ("FASB") in December 1990 and established the accounting standards for employers' accounting for "other post-retirement benefits" ("OPRBs"). Under the provisions of SFAS 106, Citizens is required, for financial reporting purposes, to use the accrual method of accounting for OPRBs (i.e., healthcare and life insurance benefits provided to retirees.). Prior to 1993, those costs were accounted for on a cash or pay-as-you-go basis, whereby such costs were expensed when the benefits actually were paid to or on behalf of the employees after retirement. Under SFAS 106, the OPRB expense is accrued while the employees are employed. The change from the cash to accrual basis results in a "transition obligation" equal to the unrecognized amount of accumulated OPRBs in excess of the value of any plan assets at the time SFAS 106 initially is applied. SFAS 106 permits the delayed recognition of the transition obligation over the average remaining service period of active participants, or 20 years, if the average remaining service period is less than 20 years.

The Commission previously has recognized that accrual accounting is a proper and preferred method of recording SFAS 106 expense. There is no dispute that Citizens' post-retirement benefits are a form of compensation that are reasonable and necessary to attract and retain employees. This Commission has found that, to the extent possible, the costs of providing utility service should be matched with the period in which the service is rendered. Citizens' current rates should reflect the current cost of these benefits, as determined in accordance with GAAP. Current recovery through rates of the SFAS 106 accruals will provide a proper matching of revenues and expenses by including in current rates the full cost of current service, and by including the cost of post-retirement benefits earned during the current period. Continuing to use the pay-as-you-go, or cash basis, method for ratemaking is no longer appropriate because it would fail to include in current rates a significant current cost of service.

These reasons for adopting SFAS 106 for ratemaking apply equally to Petitioner. We have approved the use of SFAS 106 for ratemaking purposes in other cases where we considered the issue. See, Indianapolis Water Co. (IURC 8/10/094), Cause Nos. 39713 and 39843, p. 45;

Indiana-American Water Co. (IURC 2/4/94), Cause No. 39595, pp. 13-16, 150 PUR4th 141, 153-155; Gary-Hobart Water Corp. (IURC 12/1/93), Cause No. 39585, pp. 4-5; Indiana Gas Company (IURC 5/8/95), Cause No. 39353, Phase II.

The Commission, therefore, finds that Petitioner should be allowed to recover OPRB costs on an accrual basis.

The accounting and regulatory issues relating to SFAS 106 are described in detail in the Commission's Order dated December 30, 1992 in Cause No. 39348 (the "Generic Order") issued in the generic investigation of SFAS 106. In the Generic Order, the Commission provided that an Indiana utility can request recovery of SFAS 106 expenses in its general rate proceedings, but must demonstrate that the expense is prudent and reasonable. (Generic Order, at 35).

In the Settlement Agreement, the Settling Parties agreed that Petitioner's SFAS 106 transition obligation at March 31, 2002 was $5,208,014. The Settling Parties further agreed that Petitioner should be allowed to recover the transition obligation, as well as the accruals added to this account through the date of this Order over a 12-month period.

Petitioner's witness Carey B. Lykins, Senior Vice President and Chief Financial Officer, testified that if the Commission did not allow recovery of the accrual amount as agreed in the Settlement Agreement, then the difference between that amount and the amount authorized by the Commission would have to be written off, thereby reducing Citizens' net income and retained earnings each year. This could have a detrimental effect on the future bond ratings of Citizens and thus harm its customers through higher borrowing costs.

The Commission finds that Citizens' SFAS 106 expense is prudent and reasonable and Citizens should be allowed to recover the FASB 106 accrual amount as reflected in this Settlement Agreement. The Commission further finds that the Settling Parties' agreement that Citizens recover OPRB costs through an offset to the CBT is a reasonable means to recover such costs through "rates."

(c) Customer Benefit Tracker. Petitioner's witness Lykins testified regarding the agreed-upon CBT. Citizens' management and Board believe it is appropriate to distribute some portion of the funds from unregulated businesses to gas customers each year. However, currently there is no rate tracking mechanism by which available non-regulated income from CBP can be tracked back to gas customers.

Citizens' customers may benefit from the CBT because with the addition of CBP's available non-regulated funds, more funds potentially will be available for distribution to gas customers. The CBT also allows non-regulated funds to be used to offset SFAS 106 costs and other expenses, which otherwise would have to be recovered through increased base rates. In the Settlement Agreement, Citizens agreed not to put into effect new bases rates and charges prior to September 30, 2003.

The evidence shows that the CBT may provide a greater benefit to Citizens' customers than the existing Manufacturing and Oil Division trackers. Moreover, under the agreed-upon

CBT, Citizens will use some of the funds generated by non-regulated activities to cover costs associated with its SFAS 106 costs and certain regulatory case expenses, which otherwise could have increased base rates.

The Commission, therefore, finds that Petitioner should be allowed to implement the CBT as set forth in the Settlement Agreement.

5. **Changes Made to the Settlement Agreement Exhibits as a Result of the Technical Conference**. During the September 23, 2002 Technical Conference, the Commission Staff raised several issues regarding Citizens' rates and charges for residential customers. Although residential customers are not eligible to select a 3rd Party Supplier at this time, the rates and charges for those customers have been separated to reflect the Gas Delivery and Gas Supply components. During the technical conference, Citizens also agreed to work with the Commission's Consumer Affairs Division in developing a customer communication plan for implementation of the new tariffs and resulting bill format changes.

Following the Technical Conference, Citizens made several changes to the rate schedules applicable to residential customers, as well as to its proposed Terms and Conditions of Service in order to make those rates easier for the general public to understand. Those changes were included in Citizens' Notice of Filing Certain Revisions to the Proposed Rates and Charges and Terms and Conditions of Service Pursuant to September 23, 2002 Technical Conference. Citizens amended the Terms and Conditions of Service to include definitions for the terms "Delivery Charge," "Gas Supply Charge" and "Facilities Charge," which are used in the rates applicable to residential customers.

Citizens also amended the rate schedules for Residential Domestic and Residential Heating Delivery Services by deleting references to Balancing Charges. The rates for Variable-Rate Supply service provided to residential customers also were simplified by combining the Capacity, Commodity and Balancing charges into a single rate instead of three separate charges.

6. **Conclusion**. We find, based upon the applicable law and evidence presented, that the Settlement Agreement and the modified ARP are reasonable, in the public interest and should be approved in their entirety. Finally, with regard to future citation of the Settlement Agreement and Order, we find approval herein should be construed in a manner consistent with our findings in In Re Richmond Power & Light, Cause No. 40434, (IURC 03/19/97).

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement filed on August 27, 2002, as modified by Citizens' Notice of Filing Certain Revisions to the Proposed Rates and Charges and Terms and Conditions of Service Pursuant to September 23, 2002 Technical Conference ("Notice") is hereby approved in all respects, and the terms and conditions thereof shall be and hereby are incorporated herein as a part of this Order.

2. Consistent with the terms of the Settlement Agreement, the ARP as modified is approved and the Commission's regulation of Citizens shall be modified consistent with the terms and conditions of the Settlement Agreement.

3. Citizens shall be, and hereby is, authorized to (a) retain from the Available Funds of the CBT $410,000 each year for its ongoing OPRB costs; and (b) retain from the Available Funds of the CBT its transition obligation over a period of 12 years, as set forth in the Settlement Agreement.

4. Citizens shall be, and hereby is, authorized to retain from the Available Funds of the CBT such portion of its SFAS 71 regulatory assets related to unbundling costs, as set forth in the Settlement Agreement and Finding No. 3(c).

5. Citizens shall file tariff sheets consistent with the Settlement Agreement and Notice, pursuant to this Order, which shall become effective upon filing with and the approval of the Commission's Gas/Water/Sewer Division.

6. This Order shall be effective on and after the date of its approval.

<u>McCARTY, HADLEY AND ZIEGNER CONCUR; RIPLEY ABSENT</u>:
APPROVED: DEC 11 2002

I hereby certify that the above is a true and correct copy of the Order as approved.

Nancy E. Manley

Nancy E. Manley
Secretary to the Commission

Petitioner's Exhibit
LSP-4

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST, D/B/A CITIZENS GAS & COKE UTILITY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE AND FOR APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES APPLICABLE THERETO, APPROVAL UNDER IC 8-1-2.5 OF AN ALTERNATIVE REGULATORY PLAN IMPLEMENTING AN UNCOLLECTIBLE EXPENSE ADJUSTMENT MECHANISM, A DEMAND SIDE MANAGEMENT AND RATE DECOUPLING MECHANISM AND APPROVAL OF OTHER CHANGES TO ITS GENERAL TERMS AND CONDITIONS FOR GAS SERVICE	)	**CAUSE NO. 42767**

<u>STIPULATION AND SETTLEMENT AGREEMENT</u>

The Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas & Coke Utility ("Citizens"), the Indiana Office of the Utility Consumer Counselor ("OUCC") and Intervenor Citizens Industrial Group ("CIG") (collectively, the "Settling Parties") solely for purposes of compromise and settlement of issues arising from the Order entered October 19, 2006 in this proceeding, stipulate and agree that the terms and conditions set forth herein represent a fair, reasonable and just resolution of the matters raised by Citizens and CIG in their respective petitions for rehearing and reconsideration, subject to their incorporation into a final order of the Indiana Utility Regulatory Commission ("Commission") without modification or further condition that may be unacceptable to any Party.

The Settling Parties agree that Section III of this Stipulation and Settlement Agreement ("Settlement") relating to the Energy Efficiency Adjustment, including the referenced exhibits, shall be considered the Settling Parties' agreement on gas rate decoupling and energy efficiency programs. Section III of the Settlement is modeled after a similar energy efficiency program for Vectren Energy Delivery of Indiana ("Vectren"), which the Commission approved by final order dated December 1, 2006 in consolidated Cause Nos. 42943 and 43046. As the Commission found in the Vectren case, it has the authority to approve gas rate decoupling under Ind. Code § 8-1-2-42(a), and does not need to utilize the Alternative Regulatory Plan ("ARP") statute to approve tracking mechanisms.

The Settling Parties further agree that all of the terms and conditions of this Settlement set forth below represent a global resolution of all of the issues that were raised, or which could have been raised, in the pending petitions for rehearing and reconsideration or on appeal of the Order, and constitute a just and reasonable compromise consistent with the public interest. Commission approval of this Settlement will resolve all matters pending before the Commission in Cause No. 42767 and before the Indiana Court of Appeals in Consolidated Cause No. 93A02-0611-EX-1034. Upon Commission approval of this Settlement in its entirety, without any change that is unacceptable to any Settling Party, Cause No. 42767 will be closed, except to the extent necessary to ensure the implementation and enforcement of the terms of this Settlement.

I. Introduction

1. On October 19, 2006, the Commission approved its final Order in this base rate case and ARP proceeding (the "Order"). The Order authorized Citizens to increase by $14,736,442 its annual operating revenues from rates and charges for gas service to produce total annual operating revenues of $428,962,372. The Order also "adopt[ed] the OUCC's [rate design and] cost of service study to implement the [approved] rate increase." Citizens was required to "conform to the determinations made in Finding No. 8 concerning the method of implementing the rate increase." The resulting allocation of the overall authorized increase in annual operating revenues among Citizens' customer classes resulted in an approximate increase of 63% to the distribution rates of the Large Volume class.

2. The Order also approved an increase in Citizens' revenue requirements of $470,588 for certain identified energy efficiency programs, but rejected Citizens' proposed ARP for approval of a Volume Variance Conservation Adjustment ("VVCA") decoupling mechanism, which Citizens believed would encourage demand-side management and the efficient use of energy, while protecting Citizens from the potential loss of margin attributable to warmer than "normal" weather and energy conservation and protecting its customers from colder than "normal" weather and weather-related volatility. In its findings rejecting the proposed VVCA, the Commission "encourage[d] Citizens to continue to investigate the development of a decoupling mechanism . . . ." The Commission further indicated that "any such investigation into the issue should . . . be based upon a collaborative effort between Citizens, the OUCC, the Commission, and other interested stakeholders. . . ." As outlined in detail in Section III below, this Settlement includes a decoupling mechanism and a collaborative energy efficiency program modeled after what the Commission recently approved for Vectren in consolidated Cause Nos. 42943 and 43046.

3. The Order also directed Citizens to "file tariffs and terms [and] conditions of service which conduct cash outs in 'cash' on both sides of the cash out transaction." Finally, Citizens was required to file with the Gas/Water/Sewer Division of the

Commission "tariff schedules set out in accordance with the Commission's rules for filing utility tariffs." Citizens made the foregoing filing of its compliance rates and charges on October 23, 2006.

4. On November 8, 2006, Citizens and CIG each filed with the Commission Petitions for Rehearing and Reconsideration as to certain issues and requested the Commission to reconsider certain findings and conclusions in the Order. CIG also filed a Supplemental Petition for Reconsideration on December 5, 2006 requesting partial reconsideration of the Commission's November 21, 2006 Nunc Pro Tunc Order, which amended the Order.

5. On November 17, 2006, Citizens and CIG filed their respective Notices of Appeal with the Commission and served the Clerk of the Indiana Court of Appeals in accordance with Indiana Appellate Rule 9(A). The Court of Appeals on January 2, 2007 consolidated Citizens' appeal and the CIG appeal as Consolidated Cause No. 93A02-0611-EX-1034 and stayed the appeal of the Order pending the completion of the rehearing process before the Commission. The Court also ordered Citizens and CIG to provide the Court with status reports every 30 days. Citizens and CIG filed a joint status report with the Court on February 1, 2007.

6. While rehearing was pending and the consolidated appeals stayed, the Settling Parties engaged in collaborative discussions in an effort to determine whether they could resolve the issues raised by the petitions for rehearing and reconsideration through a settlement and avoid further litigation. The Settling Parties have negotiated this Settlement in order to resolve certain issues without the time delay, additional expense and uncertainty resulting from further litigation before the Commission and on appeal.

7. The Settling Parties also negotiated this Settlement in the context of the challenges posed by sustained high and volatile gas prices. Because gas costs represent approximately 70% of a typical residential customer's bill, efforts to reduce usage address the largest portion of customers' bills. Citizens believes that in order to align its interests with the interests of its customers in reduced gas usage, the Commission should approve a decoupling mechanism and allow it the opportunity to recover the non-commodity costs of providing gas service to its customers that were found to be appropriate for recovery in Cause No. 42767, even if customer usage of gas declines due to energy efficiency, demand destruction, or otherwise. As previously noted, since issuing the Order, the Commission has approved a settlement agreement authorizing implementation of a similar decoupling mechanism for Vectren. *See* the December 1, 2006 Order in consolidated Cause Nos. 42943 and 43046.

II. <u>Settlement of Cost Allocation and Rate Design Issues</u>

8. Both Citizens and CIG filed petitions for reconsideration of the Commission's cost of service determination and have identified that determination as an anticipated appeal issue. In order to resolve the dispute regarding cost of service issues

and mitigate rate shock to the Large Volume class resulting from the Commission's Order, and guided by principles of "gradualism" as previously applied by the Commission, the Settling Parties agree that the amount of the revenue requirement increase allocated to the Large Volume class should be 50% of the amount set forth in the compliance rates Citizens filed on October 23, 2006.

9. The Settling Parties further agree that as a result of the foregoing, the revenue requirements allocated to the other customer classes should be revised as set forth on Exhibit No. 1 attached hereto.

10. In addition, the Settling Parties agree that Citizens should create a new High Load rate class for Large Volume customers with volumes of 200,000 Dth per year or greater and a load factor of 50% or greater. The new High Load rate class initially will contain seven customers. With the exception of the applicability requirements, the rates and terms of service applicable to the new High Load class initially will be identical to those of the Large Volume class. The proposed rate schedule for the new High Load rate class is attached hereto as Exhibit No. 2. The Settling Parties agree that Commission approval of this Settlement will resolve the issues set forth in the reconsideration petitions of CIG and Citizens regarding cost of service and rate design without any Commission or appellate determination on the merits of those petitions, that no Settling Party has acquiesced in or waived any position with respect to the appropriate methodology for determining cost of service or rate design, and accordingly, in future proceedings, no presumption will be given to any prior methodology for determining cost of service or rate design.

III. Settlement on Gas Rate Decoupling, the Energy Efficiency Collaborative Process, and the Energy Efficiency Adjustment (Rider E)

A. Energy Efficiency Portfolio and Oversight Board

11. The Order authorized Citizens to implement a new schedule of rates and charges for services and determined a level of costs to be recovered via those new rates and charges, which were designed using a projected level of customer usage. To permit Citizens the opportunity to recover its authorized level of non-gas costs, the Settling Parties agree that Citizens shall implement the Energy Efficiency Adjustment ("EEA"), as set forth in the tariff sheet attached hereto as Exhibit No. 3. The EEA Rider is modeled after a similar tariff mechanism approved for Vectren in consolidated Cause Nos. 42943 and 43046. The EEA Rider contains two (2) components: (1) the Energy Efficiency Funding Component ("EEFC"), and (2) the Sales Reconciliation Component ("SRC"). As explained in more detail below, the EEFC will provide additional funding for energy efficiency programs, and the SRC will "decouple" Citizens' non-gas cost recovery from its sales volumes.

12. For purposes of this Settlement, the following definitions shall apply:

a) "Energy Efficiency Portfolio" or "Portfolio" refers to the energy efficiency programs approved in Finding No. 9 of the Order, which will be implemented during Phase 1 (as defined in paragraph 13 below), as well as the Portfolio subsequently established in Phase 2 (as defined in paragraph 16 below), using the process described herein.

b) "Settling Parties" refers to the parties to this Settlement, as identified on the first page of this Settlement.

c) "Administrator(s)" refers to the independent third party administrator(s) selected by the Oversight Board to be responsible for the administration and review of one or more of the ongoing programs approved under the Portfolio commencing in Phase 2.

d) "Energy Efficiency Adjustment" or "EEA" or "EEA Rider" refers to the new tariff mechanism to achieve decoupling and for recovery of certain costs described hereafter.

e) "Oversight Board" refers to the energy efficiency oversight board, a representative body that will be responsible for monitoring and administering the progress and effectiveness of Indianapolis, Indiana 46282 the ongoing Portfolio, and for making key decisions with respect to the direction of the Portfolio and use of Portfolio funding.

f) "Actual Margins" refers to the monthly margins for each Rate Schedule, prior to the SRC Adjustment.

g) "Adjusted Order Granted Margins" refers to the order granted monthly margins for each Rate Schedule, as approved in Citizens' most recent general rate case, as adjusted to reflect the change in number of End-Use Customers from the order granted End-Use Customer levels.

13. The first phase of the Portfolio implementation (Phase 1) will consist of the 12 months commencing on the first day of the first month subsequent to the Commission's issuance of an order approving this Settlement in its entirety without change(s) or condition(s) unacceptable to any Settling Party. During Phase 1, Citizens will act as Portfolio Administrator, with the identified Energy Efficiency Portfolio and specified initial funding levels for the programs set forth in Finding No. 9 of the Order, which includes funding for research and development and Portfolio administration. With input from the Oversight Board, Citizens will focus its efforts to effectively implement and expand existing energy efficiency programs directed at the core residential and commercial uses of gas and will seek to build customer awareness of the availability of the energy efficiency programs. During Phase 1, the Oversight Board will consider, among other things, whether Citizens should be permitted to recover additional amounts in its rates (via the EEFC) to fund further energy efficiency initiatives or studies, such as the market potential study, customer education, and employee education discussed below. Citizens, however, will not be required to increase the funding levels for its Energy

Efficiency Portfolio, or studies, beyond the funding level approved in Finding No. 9 of the Order, without first receiving Commission authority to recover any such additional costs in rates through the EEFC.

14. The Oversight Board will be able to review the initial Portfolio and the various program results in Phase 1 and direct the expansion of the programs defined under the Portfolio in Phase 2. The Oversight Board will consist of one representative from each of the following: (1) Citizens, (2) a designated member of the Commission Staff (to the extent it chooses), (3) the OUCC, (4) Indiana Lieutenant Governor's Indiana Energy Group (invited as a non-voting member), (5) Energy Center at Discovery Park, Purdue University (invited as a non-voting member), (6) Center for Energy Research/Education/Service, Ball State University (invited as a non-voting member), (7) Alliance to Save Energy (invited as a non-voting member), and (8) others as determined by unanimous vote of its voting members. Throughout Phase 1 of the Portfolio, Citizens and the Oversight Board will continue to work together in a collaborative process and will work on the design of an appropriate methodology to be used to evaluate the performance of the energy efficiency programs that were approved in the Order. The Oversight Board will agree to and adopt a methodology to be used to conduct the evaluation of Phase 1 of the Portfolio and will review the effectiveness of the methodology and may modify it thereafter to the extent reasonably necessary. Appropriate metrics will include evaluations of participation levels, energy savings, customer bill reductions and gas supply cost savings.

15. During Phase 1 of the Portfolio, Citizens will initiate a market potential study of its service territory. The Oversight Board will select the contractor to perform the market potential study, and Citizens may recover the cost of the study via the EEFC, or use a portion of the funds built into base rates for the Energy Efficiency Portfolio in the Order. The results of the market potential study are necessary to provide the planning foundation to determine the optimal mix of cost effective programs to be implemented under the Energy Efficiency Portfolio in Phase 2.

16. The Settling Parties agree that from a longer term perspective, the Oversight Board will have the responsibility to administer the Portfolio and should consider the expertise and innovation that may be available through the use of firms that have experience with energy efficiency and technologies for administration of its programs. Therefore, after completion of the market potential study, Phase 2 of the Portfolio will be devoted to selection and use of all Administrator(s). Within thirty (30) days after completion of the market potential study, the Oversight Board will commence the process that will result in a solicitation of proposals for program administration of Phase 2 of the Portfolio. The Oversight Board will prepare a Request-For-Proposal ("RFP") that will define the role of the Administrator(s), the duration of the relationship, the performance standards applicable to the Administrator(s), and the method of evaluation of the Energy Efficiency Portfolio that will be administered. In developing the RFP, the Oversight Board may retain a consultant, the cost of which may be recovered through the EEFC. Upon final selection, the Oversight Board will then negotiate final contract terms with the selected Administrator(s). The Oversight Board will use good

faith efforts to reach consensus on all aspects of the process of selecting the Administrator(s) of the programs in the Portfolio. In the event such efforts fail to yield a consensus, the Oversight Board will select the Administrator(s) through a majority decision of its voting members. Disputes among the voting members of the Oversight Board with respect to the selection of the Administrator(s), and other issues, are subject to the dispute resolution provisions set forth in paragraph 45 of this Settlement.

17. Citizens may submit one or more program administration proposals of its own for the Oversight Board to consider in response to the RFP. However, in order to maintain a fair and impartial competitive selection process, it is appropriate that if Citizens (or an affiliate) determines that it wishes to submit a proposal, it will not participate in the development of the RFP or in the RFP selection process for the specific program(s). If Citizens chooses to submit a proposal, it must: (a) submit its proposal to the Oversight Board by the same deadline indicated in the solicitation, (b) recuse itself from participation in all deliberations, discussions and voting related to the contract award selection process for the specific program(s) at issue, and (c) forfeit its right to raise objections on issues related to the foregoing contract award selection process. Moreover, if Citizens (or an affiliate) is selected to be Administrator of a program, Citizens will recuse itself on Oversight Board matters related to the specific program(s) it administers for the period during which it serves as an Administrator.

18. The Energy Efficiency Portfolio shall have an initial term of five (5) years commencing on the first day of the first month subsequent to the Commission's issuance of an order approving this Settlement in its entirety without changes or conditions unacceptable to any Settling Party. This initial term will include both Phase 1 (one year) and Phase 2 (four years). The overall funding levels for the Phase 2 Portfolio, to the extent possible, should be generally consistent with the results of the market potential study described in paragraph 15. However, the funding amount for the first year of Phase 2 will not exceed \$2.5 million, without additional Commission approval. Of this amount, \$470,588 will be recovered in Citizens' base rates, with increments above that amount to be recovered through the EEFC. With respect to the level of annual funding after the first year of Phase 2, the Oversight Board shall determine the feasibility of increasing the total funding level by up to 15% each year based upon Portfolio results and the amount of excess funds from prior years that remains available to be spent. Thus, in year three of the Portfolio, the Oversight Board could agree to increase the prior year funding amount of \$2.5 million by up to \$375,000. Another 15% increase could be agreed upon in subsequent years, with a maximum level reached in the fifth year of \$3,802,188. The five year period should provide a sufficient period of time to assess Portfolio effectiveness and to allow development of relationships with vendors, contractors and HVAC dealers in Citizens' service territory. With respect to Portfolio funds that are unspent in any year, if less than \$1 million, such funds may be allocated by the Oversight Board to existing or similar conservation programs in the subsequent Portfolio year. The Oversight Board retains the discretion to propose that Citizens use such unspent funds outside of this specific Portfolio, such as to fund a supplemental low-income weatherization program or some other assistance program, with Commission approval. To the extent unspent funds exceed \$1 million in any given year; any decision by the

Oversight Board with respect to the use of those funds will be subject to Commission approval. Funds remaining at the end of year five will either be rolled into the extended or replacement Portfolio or, if neither is ultimately approved by the Commission, then such remaining amount shall be reconciled through the EEFC and flowed back to customers.

19. The Settling Parties agree that certain reasonable performance measures will be instituted to assure appropriate Portfolio oversight. In order to establish the performance metrics and conduct appropriate review of those metrics, the Oversight Board may annually retain a consultant to assist in the development and review of metrics associated with Phase 2 of the Portfolio, with EEFC funding annually for the consultant's services. While the Oversight Board will have discretion in the design of the performance metrics, the Settling Parties envision that there will be multiple metrics each year. The Settling Parties also anticipate that the performance standards set for the Administrator(s) in the respective contracts will be designed to encourage performance that meets the metrics.

20. The Oversight Board will make Portfolio decisions using a consensus process. With respect to material decisions, to the extent the Oversight Board cannot reach a consensus after a good faith effort by all members, and as a result a decision is reached by a mere majority, any individual member can raise objections to a majority decision by filing such objections with the Commission in this proceeding. Regardless of a pending formal objection, decisions made by the majority of the Oversight Board will be implemented until such time as the Commission issues an order providing further direction. The member may ask the Commission as part of a filed objection for a brief stay of implementation of a decision to allow the Commission to rule on the objection. In the event the Oversight Board deadlocks on a voting issue, then the members of the Oversight Board shall present their positions to the Commission for a decision, subject to the dispute resolution provisions in paragraph 45 of this Settlement.

21. The Oversight Board will receive data related to program cost and performance from Citizens and from the Administrator(s). The Oversight Board will evaluate such data and provide annual reports to the Commission related to both the Portfolio results and the related programs, including pertinent metrics of the effectiveness of the various programs. To the extent supported by program results after at least one year of experience with the Administrator(s), the Oversight Board may propose an increase in annual funding above the levels described in paragraph 18 above by filing a motion with the Commission in this proceeding. The Settling Parties agree that the long term goal of the Portfolio is to capture in a cost effective manner the potential for energy efficiency as represented by reductions in gas usage among the residential and general service customers within Citizens' service territory.

22. Citizens will direct all of its employees to advocate energy efficiency to all of its customers and continue to provide employee training to complement the activities undertaken through the Portfolio. The efforts of Citizens to complement the Portfolio by proactively encouraging cost effective energy efficiency shall be subject to annual review

by the Oversight Board. Reports related to these efforts will be provided to the Oversight Board.

B. **Energy Efficiency Adjustment Rider**

23. The EEA Rider shall consist of: (1) an EEFC, and (2) a SRC. The EEFC will recover the cost of the Energy Efficiency Portfolio not funded from Citizens' base rates. However, the expansion of the Portfolio will require more comprehensive annual budgets, and incremental funding above and beyond base rates will be necessary. The foregoing funding will be achieved through the EEFC.

The SRC constitutes the decoupling mechanism that will allow Citizens to recover its non-gas costs as authorized in the Order (as adjusted to reflect the change in number of End-Use Customers from the order granted End-Use Customer levels). For each Citizens' customer class subject to the SRC (i.e., Gas Rate Nos. D1, D2, D3 and D4), the SRC shall recover the Margin Difference between Actual Margins and the Adjusted Order Granted Margins approved in Cause No. 42767 (i.e. $108,932,369, as adjusted for End-Use Customer levels). The Margin Difference shall be calculated monthly beginning with the first month after the Commission's approval of this Settlement, and shall be deferred, without carrying cost, for subsequent recovery (or refund) via the SRC. Exhibit No. 3 contains the tariff sheet(s) for the EEA Rider, which includes the EEFC and SRC components.

24. During the term of this Settlement, the EEA shall be in effect unless modified in a subsequent Citizens rate case in accordance with paragraph 29 below, or so long as the Oversight Board, by consensus of its voting members, believes the EEA Rider will be of benefit to Citizens' customers.

25. The EEA Rider is structured to encourage proactive and good-faith efforts by Citizens, in collaboration with the Oversight Board, to promote the Energy Efficiency Portfolio of programs, which will provide customers with more information, efficiency measures and tools to reduce the quantity of natural gas otherwise required to meet their energy needs and reduce the customers' total monthly bills. In the Order, the Commission approved an increase in Citizens' revenue requirements of $470,588 to be used to fund the identified the Portfolio. It is assumed that this amount will be recovered in base rates and used to fund Portfolio. This amount will not be "tracked" through the EEFC. Incremental expenditures approved by the Oversight Board, however, will be eligible for recovery through the EEFC.

26. The EEA Rider also encourages Citizens to promote energy efficiency by addressing the current rate design that makes Citizens' ability to recover its non-commodity costs dependent on promoting increased customer sales volumes. The SRC component of the EEA essentially breaks the linkage between Citizens' customer sales volumes and recovery of its predominately fixed non-commodity costs, making it possible for Citizens to encourage its customers to reduce natural gas purchases, without creating financial harm to Citizens.

27. Effective January 1st of each year, Citizens shall establish and collect (or refund) the SRC rates required to recover (or refund) over the subsequent 12-month period the accumulated deferred Margin Differences. Once established, the SRC rates shall remain in effect for 12 months, subject to adjustment each year for a successive 12 month period. The annual SRC update also shall include a reconciliation to ensure that the accumulated deferred Margin Differences are not over or under-recovered as a result of variances between estimated and actual data. By December 1 each year, the OUCC and the Commission shall be provided with all data and calculations used as the basis for estimates, as well as the calculation of the SRC pursuant to a filing using the Commission's 30-day filing process. The actual data shall be derived from Citizens' fiscal year end (September 30th) audited financial statements. The calculated Margin Differences will be recorded on Citizens' books on a monthly basis. Citizens will timely provide to the OUCC and the Commission any additional information reasonably necessary to evaluate Citizens' SRC filings.

28. The Settling Parties understand that Citizens will participate in Cause No. 43180, *i.e.*, the Commission's investigation into all matters involving decoupling and energy efficiency alternatives by natural gas utilities, and that Citizens' experience with the EEA mechanism will be a valuable source of data for evaluating whether it should be continued or modified.

29. During the term of this Settlement, the OUCC and Citizens reserve the right to propose in any Citizens base rate case or as otherwise provided in this Settlement, a modification of rate design as an alternative to the SRC that would be similarly intended to eliminate the link between customer usage and non-commodity cost recovery for the residential and commercial rate classes. To the extent such a proposal is made, the OUCC and Citizens reserve all rights to take positions regarding the adoption of such a rate design. The Party proposing the change will bear the burden of proof.

30. In no event will the final order in a Citizens base rate case during the term of this Settlement eliminate the SRC absent adoption of an alternative rate design approved by the Commission that is consistent with the objective of providing non-commodity cost recovery regardless of usage. To the extent the SRC remains in place at the conclusion of Citizens' next base rate case, the final order in such case will establish the margin approved in the most recent rate case (as adjusted to reflect the change in number of End-Use Customers from the order granted End-Use Customer levels) to be compared to Actual Margin to determine the Margin Difference to be recovered (or refunded) via the SRC.

31. The Settling Parties agree that, to the extent the EEA is not modified in a subsequent proceeding as described in paragraph 29, the EEA shall be thoroughly reviewed to ensure that it is working as contemplated in this Settlement, and that the review thereof shall include but not be limited to technical conferences including Commission staff, and shall occur no later than three (3) years after the date this Settlement is approved by the Commission.

32. Citizens acknowledges and agrees that its commitment to promote a long term, robust Energy Efficiency Portfolio was integral to the OUCC's decision to agree to a cost recovery mechanism that would support Citizens' ability to promote reductions in usage without impairing its the ability to recover the non-commodity costs of providing gas service to customers that were found to be appropriate in Cause No. 42767. Based on the evaluation of the effectiveness of the Portfolio during Phase 2, Citizens, after engaging in discussions with the OUCC about Portfolio results and cost recovery mechanisms, will file for a three (3) year extension of the Portfolio and EEA, or propose to discontinue or modify the current Portfolio and EEA, no later than nine (9) months prior to the conclusion of the initial five (5) years following the effective date of the Commission order approving this Settlement. Citizens agrees to bear the legal burden of proof in a filing that seeks Commission approval to extend the EEA under this Settlement for an additional period of time or to approve a cost recovery mechanism similar to the EEA.

33. If the term of the Settlement expires prior to the Commission entering a final order on a subsequent filing as outlined above, the Settling Parties agree that the Portfolio and the EEA shall continue in effect until final action by the Commission. Thereafter, the Settling Parties agree that either party may file a complaint regarding the appropriateness of any rate design that does not include a commitment to an Energy Efficiency Portfolio, and the Settling Parties agree that neither waives any rights with respect to positions they may take in any such subsequent proceeding at the expiration of the five (5) year term of this Settlement.

IV. <u>Settlement of Cash Out Tariff Issue</u>

34. CIG sought reconsideration of the Order and the November 21, 2006 Nunc Pro Tunc Order with respect to balancing tolerances and penalties. Citizens sought reconsideration of the Order regarding cash out of imbalances. Both parties have identified the balancing and cash out matters as anticipated appeal issues. In the Order, the Commission "instruct[ed] Citizens to file tariffs and terms [and] conditions of service which conduct cash outs in 'cash' on both sides of the cash out transaction." The Commission's finding was, in part, based on the fact that the cash-out provisions in the tariffs of certain other Indiana gas distribution utilities provide for cash-outs to be paid in *cash*, as distinct from Citizens' tariff which called for providing a "*credit*" on the bill. However, Citizens' premiums and discounts applicable to cash outs are lower than those of the other Indiana gas distribution utilities which provide for cash to be paid when cashing out.

35. Citizens complied with the Order and revised its tariffs to provide cash outs in "cash." Citizens will continue to conduct cash outs in "cash" on both sides of the cash out transaction, as reflected in the tariffs and terms and conditions for service filed with the Commission on October 23, 2006.

36. In exchange for Citizens' agreement to continue conducting cash outs in "cash" and to resolve the disputed balancing issues, the Settling Parties agree that Citizens will implement the same imbalance premium and discount percentages as are included in Appendix E of the Indiana Gas Company, Inc. D/B/A Vectren Energy Delivery of Indiana, Inc. (Vectren North) tariff.

37. In the Order, the Commission also found that "Citizens' proposed change to include capacity costs in the charge for under-deliveries, but exclude capacity costs in the credit given for over-deliveries should be accepted." In exchange for maintaining the Commission-approved exclusion of pipeline capacity costs from the Applicable Gas Supply Charge for positive usage imbalances, Citizens will modify its D5 – Large Volume Delivery Service tariff to replace its Tiered Basic Delivery Service charges with a non-tiered Basic Delivery Service charge, set at what would otherwise be the Tier 3 level. The new High Volume Delivery Service tariff will use the same non-tiered Basic Delivery Service charge. The following tolerances and penalties will apply to Supplier Groups and End-Use Customers.

a. The daily premiums and discounts applicable to Citizens' Basic Usage Balancing Service (Gas Rate No. A3) during Non-Operational Flow Order conditions will be revised to read as follows:

Under-deliveries (negative usage imbalances)	
Imbalance	**3rd Party Supplier will pay Citizens the following multiple of the Applicable Gas Supply Charge (including capacity costs)**
>0% not >20%	No cash out; carried to month end
>20% not >30%	1.1
>30% not >40%	1.2
>40%	1.4

Over-deliveries (positive usage imbalances)	
Imbalance	**Citizens will pay 3rd Party Supplier the following multiple of the Applicable Gas Supply Charge (excluding capacity costs)**
>0% not >20%	No cash out; carried to month end
>20% not >30%	.9
>30% not >40%	.8
>40%	.6

b. The monthly premiums and discounts applicable to Citizens' Usage Balancing Service (Gas Rate No. A2) and Basic Usage Balancing Service (Gas Rate No. A3) will be as follows:

Under-Deliveries (negative usage imbalances)	
Imbalance	**3rd Party Supplier will pay Citizens the following multiple of the Applicable Gas Supply Charge (including capacity costs)**
>0% not >10%	No cash out; carried over to following month
>10% not >20%	1.1
>20% not >30%	1.2
>30%	1.4

Over-Deliveries (positive usage imbalances)	
Imbalance	**Citizens will pay 3rd Party Supplier the following multiple of the Applicable Gas Supply Charge (excluding capacity costs)**
>0% not >10%	No cash out; carried over to following month
>10% not >20%	.9
>20% not >30%	.8
>30%	.6

c. Cash outs of negative daily imbalances (under-deliveries) greater than 5% under Operational Flow Order conditions will be subject to the following imbalance charges:

i. For each therm of a negative daily net usage imbalance greater than 5% percent, the greater of the highest per-unit gas cost paid by Citizens on the date of non-compliance or the daily cash out charge as calculated above; plus

ii. The payment of all other charges incurred by Citizens and attributable to the 3rd Party Suppliers' imbalance, including pipeline penalty charges on the Operational Flow Order shortfall quantities; plus

iii. An Operational Flow Order imbalance charge of $1.00 per therm on the portion of the daily imbalance that is greater than 5%; plus

iv. Applicable taxes.

d. Cash outs of positive daily imbalances (over-deliveries) greater than 5% under Operational Flow Order conditions will be subject to the following provisions:

i. Citizens will pay the 3rd Party Supplier for each therm of positive daily net usage imbalance greater than 5%, the lesser of the lowest per-unit gas cost paid by Citizens (excluding capacity costs) on the date of non-compliance or the daily cash out charge as calculated above;

ii. The 3rd Party Supplier will pay Citizens all charges incurred and attributable to the 3rd Party Supplier's imbalance, including pipeline penalty charges on the Operational Flow Order excess quantities and all applicable taxes; and

iii. The 3rd Party Supplier will pay Citizens an Operational Flow Order imbalance charge of $1.00 per therm on the portion of the daily positive imbalance greater than 5%.

38. Copies of Gas Rate Nos. A2 and A3 reflecting the agreed-upon imbalance provisions are attached hereto as Exhibit No. 4 and incorporated herein by reference. Exhibit No. 5 shows the revisions to the tariff sheets necessary to remove the basic delivery service charge tiers as requested by CIG.

V. Dismissal of Consolidated Appeal, Withdrawal of Petitions for Rehearing and Reconsideration, and Joint Motion to Reopen the Record

39. Upon the Commission's issuance of a final order approving the terms of this Settlement in its entirety without change(s) or condition(s) unacceptable to either Citizens or CIG, both Citizens and CIG will jointly move to dismiss Consolidated Cause No. 93A02-0611-EX-1034. In addition, Citizens and CIG will file motions with the Commission withdrawing their respective Petitions for Rehearing and Reconsideration. CIG also will move to withdraw its Supplemental Petition for Reconsideration. Finally, the Settling Parties will file a Joint Motion to reopen the Record for purposes of introduction into evidence of the Settlement, its exhibits and testimony supporting the Commission's approval of the Settlement as consistent with the public interest.

VI. Settlement Scope and Approval

40. Neither the making of this Settlement nor any of its provisions shall constitute in any respect an admission by any Settling Party in this or any other litigation or proceeding. Neither the making of this Settlement (nor the execution of any documents required to effectuate the provisions of this Settlement), nor the provisions thereof, nor the entry by the Commission of a final order approving this Settlement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

41. This Settlement shall not constitute nor be cited as precedent by any person or deemed an admission by any Settling Party in any other proceeding except as necessary to enforce its terms before the Commission, or any tribunal of competent jurisdiction. This Settlement is solely the result of compromise in the settlement process and, except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any of the Settling Parties may take with respect to any or all of the issues resolved herein in any future regulatory or other proceedings.

42. The undersigned have represented and agreed that they are fully authorized to execute this Settlement on behalf of their designated clients, and their successors and assigns, who will be bound thereby, subject to the agreement of the Settling Parties on the provisions contained herein and in the attached exhibits.

43. The communications and discussions during the negotiations and conferences attended only by any or all of the Settling Parties, their attorneys, and their consultants have been conducted based on the explicit understanding that said communications and discussions are or relate to offers of settlement and therefore are privileged. All prior drafts of this Settlement and any settlement proposals and counterproposals also are or relate to offers of settlement and are privileged.

44. The provisions of this Settlement shall be enforceable by any Settling Party, in any tribunal of competent jurisdiction, including but not limited to the Commission.

45. With respect to any disputes between the Settling Parties related to either compliance with the Settlement terms, interpretation of the Settlement terms, or decisions of the Oversight Board implementing the Settlement terms, the Settling Parties agree to engage in a dispute resolution process prior to making any filing with the Commission. When such a dispute arises, the Party with knowledge of the dispute will notify the other Party in writing, which notice shall describe the dispute, state that the issue is being submitted for dispute resolution under this provision, and set forth a date for a meeting regarding the issue within ten (10) business days. The Party receiving notice shall investigate the dispute and provide a written response no later than at the meeting of the Settling Parties. The Settling Parties may elect to engage in further discussions, or after the initial meeting, may decide to submit the issue to a mutually agreed upon mediator for review. Such mediation shall occur within forty-five (45) days. The Settling Parties may accept the mediator's recommendation, or either Party may decide to proceed with a formal proceeding before the Commission requesting a determination with respect to the dispute.

46. This Settlement is conditioned upon and subject to Commission acceptance and approval of its terms in their entirety, without any change or condition that is unacceptable to any Settling Party.

47. The Settling Parties will request Commission acceptance and approval of this Settlement in its entirety, without any change or condition that is unacceptable to any party to this Settlement.

48. The Settling Parties will work together to finalize and file an agreed upon proposed Order with the Commission as soon as possible. The Settling Parties will offer supporting testimony for the Settlement in the proceeding and will request that the Commission issue a Final Order promptly accepting and approving the same in accordance with its terms. The Settling Parties also will work cooperatively on news releases or other announcements to the public about this Settlement.

49. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of any Final Order entered by the Commission approving the Settlement in its entirety without changes or condition(s) unacceptable to any Settling Party (or related orders to the extent such orders are specifically implementing the provisions of this Agreement) and shall support this Settlement in the event of any appeal or a request for rehearing, reconsideration or a stay by any person not a party hereto.

Accepted and Agreed on this 5th day of March, 2007.

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THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST D/B/A CITIZENS GAS & COKE UTILITY

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Distrubution of Revenue Requirement by Class

Line No.	Class	A Currently Approved Revenue by Class	B Settlement Adjustment	C Proposed Revenue by Class w/ 50% Subsidy
1	Residential Non-Heat	$ 687,595	$ 15,480	$ 703,075
2	Residential Heat	$ 78,114,457	$ 1,179,512	$ 79,293,969
3	General Non-Heat	$ 1,387,278	$ 33,226	$ 1,420,504
4	General Heat	$ 27,151,603	$ 363,217	$ 27,514,820
5	Large Volume	$ 8,470,309	$ (1,593,701)	$ 6,876,608
6	NMGL	$ 86	$ -	$ 86
7	CNG	$ 25,919	$ 2,265	$ 28,184
8	Total	$ 115,837,247	$ (0)	$ 115,837,247
9	Gas Cost	$ 308,847,946		$ 308,847,946
10	Other Revenue	$ 4,277,179		$ 4,277,179
11	Total Rate Case Revenues	$ 428,962,372	$ (0)	$ 428,962,372

Exhibit No. 1

GAS RATE NO. D9

HIGH LOAD DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for consumption for a single End-Use Customer through one or more Meters supplying a single Premise where the End-Use Customer used a minimum of 2,000,000 Therms of Gas with a load factor (i.e., average daily Gas usage divided by billing demand) of greater than 50% during the twelve (12) Months prior to initiation of Gas Delivery Service under this rate schedule or, in the Utility's sole judgment, is expected to use such minimum Gas volume level during the first twelve (12) Months of service under this rate schedule.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D9, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

FACILITIES CHARGE:

Meter Class I - $50.00 Per Meter Per Month
Meter Class II - $150.00 Per Meter Per Month
Meter Class III - $600.00 Per Meter Per Month

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

METER CLASSIFICATIONS:

Meter Class I (CF/Hour)	Meter Class II (CF/Hour)	Meter Class III (CF/Hour)
250	8C	5000
425	800	5M
	1000	7M
	1400	11M
	2300	16M
	3000	23M
	1.5M	38M
	3M	56M
		102M
		4 Turbo
		6 Turbo
		8 Turbo
		12 Turbo

DEMAND CHARGE:

$0.4157 Per Therm of Billing Demand Per Month

Billing demand is determined as the highest average daily consumption during any one of the previous billing months of November, December, January, February and March. Billing demands will be adjusted annually, with bills issued for April consumption.

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

DELIVERY CHARGE:

$0.0349 Per Therm Delivered Each Month

In addition, applicable Balancing Charges from Rider A and Customer Benefit Distribution / Universal Service Program from Rider C shall apply to all Therms delivered.

BASIC DELIVERY OPTION:

End-Use Customers are eligible to elect the Basic Delivery Service Option, in accordance with the Utility's requirements. End-Use Customers choosing the Basic Delivery Service Option must select a 3rd Party Supplier for gas supply service, or act as their own Supply Agent

Basic Delivery Service charges are as follows:

$0.0275 Per Therm Delivered Each Month

In addition, applicable Balancing Charges from Rider A and Customer Benefit Distribution / Universal Service Program from Rider C shall apply to all Therms delivered.

End-Use Customers choosing the Basic Delivery Service Option must have Automatic Meter Reading Devices (AMR), provided by the Utility through Information Service, under Gas Rate No. A7.

GAS SUPPLY:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas Supply is available from the Utility through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

End-Use Customers choosing not to make a gas supply selection, either from the Utility, or from a 3rd Party Supplier, will receive Variable-Rate Gas Supply Service under Gas Rate No. S1

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

End-Use Customers electing the Basic Delivery Service Option are eligible, but are not required, to act as their own Supply Agent. As a Supply Agent, they must be an approved bidder on CMS Panhandle Eastern Pipe Line and/or Texas Gas Transmission or their successors and are expected to perform all responsibilities normally handled by 3rd Party Suppliers. These include, but are not limited to, forecasting gas supply volumes, making pipeline and Utility Daily Gas Supply Nominations, and balancing their nominations, deliveries and usage. End-Use Customers acting as their own Supply Agent are responsible for charges for Supply Administration Service, under Gas Rate No. A1, as well as for Basic Usage Balancing Service, under Gas Rate No. A3, and, if applicable, Non-Performance Charges, under Gas Rate No. A4.

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

End-Use Customers may choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Utility's requirements. It is the End-Use Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Utility.

The Utility also reserves the right to bill the End-Use Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Daily Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

Back-up Gas Supply Service, under Gas Rate No. S2, is available from the Utility to End-Use Customers for each Single Account with an annual usage at a single meter greater than 50,000 Therms, and either choosing a 3rd Party Supplier or acting as their own Supply Agent. Back-up Gas Supply Service provides for reservation of a designated level of pipeline capacity and gas supply to be available on a daily basis, in order to provide an additional measure of gas supply security. Back-up Gas Supply Service is only available to those customers choosing the Basic Delivery option and who have not opted out of Banking.

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, End-Use Customers may choose to purchase Gas Supply from the Utility under Gas Rate No. S1, with the Utility's approval.

End-Use Customers may switch 3rd Party Suppliers once each calendar year at no charge, but will not be permitted to switch from 3rd Party Supplier to System Supply or vice versa more than one time per 12-month period. End-Use Customers who switch 3rd Party Suppliers more than once each calendar year will be subject to Switching Charges, under Gas Rate No. A8.

Gas Imbalance Provisions

Delivery Imbalances for Supplier Groups, or End-Use Customers acting as their own Supply Agent, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries will be monitored on a daily basis and accumulated monthly for all End-Use Customers of a 3rd Party Supplier, in a Supplier Group, or End-Use Customers acting as their own Supply Agent. Charges for all Delivery Imbalances will be billed, at month end, to 3rd Party Suppliers, or to End-Use Customers acting as their own Supply Agent, through Non-Performance Charges, under Gas Rate No. A4.

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of gas consumed by End-Use Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A2. In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A4.

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

In addition to the Basic Delivery Service Charges applicable to End-Use Customers selecting Basic Delivery Service, Basic Usage Imbalances, for Basic Delivery Service customers, arising from differences in the level of Daily Gas Supply Deliveries compared to the level of gas consumed by the End-Use Customer, will be monitored for End-Use Customers acting as their own Supply Agent, or combined and netted, on a daily basis, for all End-Use Customers in a single Supplier Group. All daily net Basic Usage Imbalances will be calculated daily and charged, at month end, to 3rd Party Suppliers, or to End-Use Customers acting as their own Supply Agent, through Basic Usage Balancing Service, under Gas Rate No. A3.

Banking Service
All End-Use Customers contracting with 3rd Party Suppliers, or End-Use Customers acting as their own Supply Agent, will be granted Customer Banking Volumes for use throughout the year.

Customer Banking Volumes will be granted periodically by the Utility to each End-Use Customer based on the ratio of the End-Use Customer's winter season (November through March) consumption to total Utility winter season throughput, both for the preceding heating season times storage capacity available for banking. New End-Use Customers will be granted Customer Banking Volumes based on usage of similar End-Use Customers, if more specific information is not available.

If the End-Use Customer elects to change 3rd Party Suppliers, Customer Banking Volumes will remain with the End-Use Customer and will transfer from the former 3rd Party Supplier to the new 3rd Party Supplier, effective at the same time as the change in 3rd Party Supplier.

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

Banking Service Option

End-Use Customers receiving service under this rate schedule and selecting Basic Delivery Service, may opt-out of Banking Service on an annual basis in accordance with the following procedures: An eligible End-Use Customer must sign an agreement with the Utility to verify its intent to opt-out of Banking Service. Elections must occur during the Election Period, and are in force for a minimum twelve-month period. Elections become effective beginning April 1 and remain effective through March 31 of subsequent years, until the End-Use Customer requests to re-elect Banking Service during an Election Period. The End-Use Customer's ability to re-elect Banking Service is subject to the Utility's determination that sufficient interstate pipeline capacity, and/or on-system storage capacity, either exists, or can be procured by the Utility. Any costs incurred by the Utility to arrange for a re-election to Banking Service will be charged to the End-Use Customer returning. A reasonable estimate of the costs will be provided to the End-Use Customer before the End-Use Customer decides whether to re-elect Banking Service.

Basic Delivery Service charges for End-Use Customers that have opted-out of Banking Service are as follows:

$0.0195 Per Therm Delivered Each Month

In addition, applicable Balancing Charges from Rider A and Customer Benefit Distribution/ Universal Service Program from Rider C shall apply to all Therms delivered.

Incremental Banking Service

During the Election Period, the Utility will make available Incremental Banking Volumes, through Incremental Banking Service, under Gas Rate No. A9, to all End-Use Customers purchasing gas supply from a 3rd Party Supplier, End-Use Customers acting as their own Supply Agent or 3rd Party Suppliers. Requirements for use of Incremental Banking Volumes acquired by 3rd Party Suppliers or End-Use Customers either are identical to standard Banking Volumes as described below, or are in accordance with non-discriminatory standards determined by the Utility.

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

Nomination of Customer Banking Volumes
End-Use Customers' daily Banking Volume Injections or Withdrawals will be designated by their 3rd Party Supplier or End-Use Customers acting as their own Supply Agent. All Customer Banking Volumes requested to be injected or withdrawn must be nominated by the 3rd Party Supplier or End-Use Customers acting as their own Supply Agent, by the end of the gas day, in accordance with the required nomination procedures as described in the Terms and Conditions for Gas Service. Subject to the limitations described below, the Banking Injection or Withdrawal Nominations will be confirmed, in total or part, in the sole discretion of the Utility.

Confirmed Banking Injection or Withdrawal Nominations will be used in the determination of Delivery and Usage Imbalances.

The Customer Banking Volume injection period will be the period from April 1 through October 31, inclusive. Customer Banking Volume injections shall not be permitted from November 1 through March 31. By October 31 of each year, all Banking Injection Nominations must have been delivered to the Utility's City Gate. The maximum Banking Volume Injection Quantity ("BVIQ") is one-one hundred and fiftieth (1/150) of the Customer Banking Volume, less remaining inventory from the previous year. Banking Withdrawal and Injection Nominations will be done ratably, or in accordance with the Utility's operational needs.

Permission for Banking Injection Nominations in excess of the amounts set forth in the preceding section may be requested. Utility may, at its sole discretion, honor such request without discrimination.

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

If the granted Customer Banking Volume level is not reached by October 31, the Utility will purchase and inject the volume of Gas necessary to bring the Customer Banking Volume inventory to the assigned level and the End-Use Customer will be charged for that volume in accordance with the provisions of Gas Rate No. A2.

The Customer Banking Volume withdrawal period will be the period from November 1 through March 31, inclusive. Banking Withdrawal Nominations shall not be permitted from April 1 through October 31. The maximum Banking Volume Withdrawal Quantity ("BVWQ"), on any one day, shall be calculated as one-seventy fifth (1/75) of the granted Customer Banking Volumes. Banking Injection and Withdrawal Nominations will be done ratably or in accordance with the Utility's operational needs.

The BVWQ will be reduced as the withdrawal period progresses in accordance with the following table:

Applicable Dates	Maximum Daily Banking Withdrawal Quantity
Nov. 1 – Dec. 31	100% of BVWQ
Jan. 1 – Jan. 15	75% of BVWQ
Jan. 16 – Feb. 15	50% of BVWQ
Feb. 16 – March 31	25% of BVWQ

Permission for Banking Withdrawal Nominations in excess of the amounts set forth in the preceding section may be requested. Utility may, at its sole discretion, honor such request without discrimination.

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

Customer Banking Volumes must be maintained at or above minimum Customer Banking Volume inventory levels, expressed as a percentage of total Customer Banking Volumes, over the winter season, in accordance with the following table:

Date	Minimum Customer Banking Volume Inventory % of Total Capacity
At January 31	19%
At February 28	9%

No End-Use Customers will be allowed to switch back to Variable-Rate Gas Supply Service, under Gas Rate No. S1 during the winter season, unless the required minimum Customer Banking Volume Inventory balances noted above are maintained.

Up to 5% of Customer Banking Volumes may remain in inventory at the end of the withdrawal period (March 31) without penalty. If more than 5% of Customer Banking Volumes is left in inventory at the end of the withdrawal period, the Utility will purchase from the End-Use Customer all remaining Customer Banking Volumes above the 5% allowance. The purchase price will be the lesser of 90% of the applicable Variable-Rate Gas Supply Service, for the current month, under Gas Rate No. S1, or 90% of the Utility's Storage WACOG at March 31.

Supply of Last Resort

If the 3rd Party Supplier, or End-Use Customer acting as its own Supply Agent, defaults, as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days, End-Use Customers who have contracted for gas supply services from 3rd Party Suppliers, or are acting as their own Supply Agent, will have access to Supply of Last Resort Service from the Utility, under Gas Rate

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

No. S3, if available. Supply of Last Resort Service, if available, will be provided until the first day of the End-Use Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Utility's discretion. If End-Use Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated.

Nominations
3rd Party Suppliers of End-Use Customers in a Supplier Group, and End-Use Customers acting as their own Supply Agent, will be required to provide an estimate of Daily Gas Supply Nominations for the following month to the Utility by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the month. 3rd Party Suppliers of End-Use Customers in a Supplier Group, and End-Use Customers acting as their own Supply Agent, also will be required to provide Daily Gas Supply Nominations to the Utility, as stated in the Terms and Conditions for Gas Service. The Utility retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Utility.

Except as otherwise provided herein, 3rd Party Suppliers of Supplier Groups and Supplier Pools, and End-Use Customers acting as their own Supply Agent, are required to provide 50% of their Daily Gas Supply Nominations on the Panhandle Eastern Pipe Line and the remaining 50% on the Texas Gas Transmission Pipe Line and/or Heartland Gas Pipe Line (in any combination), at the 3rd Party Supplier's level. The Utility will allow, on a first-come, first-served basis, End-Use Customers with annual usage greater than 1,000,000 Therms, to notify the Utility, in writing, of an intent to nominate volumes that do not comply with the previously stated requirement regarding nomination amounts on all interstate pipelines connected to the Utility's distribution system. The initial total usage of End-Use Customers that can be exempt from the requirement is 5 Bcf. As participating End-Use Customers change their nomination practices to comply with the Utility's requirement, the Utility will open a 30-day sign-up period, allocated on a first-come, first-served basis, for additional End-Use Customers interested in nominating volumes that do not comply with the Utility's requirement.

GAS RATE NO. D9 – HIGH LOAD DELIVERY SERVICE (Cont'd)

Non-Economic Operational Flow Order
The Utility, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic Operational Flow Order is declared, the Utility will notify the affected 3rd Party Suppliers or End-Use Customers acting as their own Supply Agent, in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers, or End-Use Customers acting as their own Supply Agent, who do not comply with the Non-Economic Operational Flow Order, will be subject to the Operational Flow Order imbalance provisions of Basic Usage Balancing Service, under Gas Rate No. A3, or Non-Performance Charges, under Gas Rate No. A4.

Economic Operational Flow Order
The Utility, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Utility will notify the affected 3rd Party Suppliers or End-Use Customers acting as their own Supply Agent, in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers, or End-Use Customers acting as their own Supply Agent, who do not comply with the Economic Operational Flow Order, will be subject to the Operational Flow Order imbalance provisions of Basic Usage Balancing Service, under Gas Rate No. A3, or Non-Performance Charges, under Gas Rate No. A4.

Company Use Gas
The Utility will retain 0.6% of the volumes tendered for delivery to the End-Use Customer for Company Use Gas.

Curtailment
Service under this rate schedule may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Utility will notify End-Use Customers, and 3rd Party Suppliers, as soon as practicable, but not less than 30 minutes prior to the effective time. End-Use Customers may be directed to restrict their Gas consumption on an hourly or daily basis. End-Use Customers who do not comply with the Utility's request may be subject to Non-Performance Charges, under Gas Rate No. A4, for all Gas taken in excess of the Utility's order.

RIDER E

ENERGY EFFICIENCY ADJUSTMENT

The Delivery Charges specified in Gas Rate Nos. D1, D2, D3, and D4 shall be adjusted from time to time in accordance with the Final Orders of the Indiana Utility Regulatory Commission in Cause No. 42767 dated October 19, 2006 and [Month] , 2007 (the "Order") to reflect an Energy Efficiency Funding Component and a Sales Reconciliation Component.

ENERGY EFFICIENCY FUNDING COMPONENT ("EEFC"):

The EEFC shall recover the costs of funding energy efficiency efforts throughout the Utility's service area. These efforts may include, among others, energy efficiency programs, customer education programs, and weatherization programs designed to benefit End-Use Customers under the applicable Rate Schedules.

The estimated annual costs, plus related revenue taxes, shall be divided by projected sales volumes to determine the applicable EEFC. The actual costs recoverable and the actual costs recovered under the EEFC shall be reconciled, with any under or over recovery being recovered or returned via the EEFC over a subsequent twelve month period.

SALES RECONCILIATION COMPONENT ("SRC"):

The SRC shall recover the differences between Actual Margins and Adjusted Order Granted Margins for the applicable Rate Schedules.

Actual Margins are defined as monthly margins for each Rate Schedule, prior to the SRC Adjustment. Adjusted Order Granted Margins are defined as the Order granted monthly margins for each Rate Schedule, as approved in Utility's most recent general rate case, as adjusted to reflect the change in number of End-Use Customers from the Order granted End-Use Customer levels. To reflect the change in number of End-Use Customers, Order granted margin per End-Use Customer is multiplied by the change in the number of End-Use Customers since the like month during the test year, with the product being added to the Order granted margins for such month.

The Utility shall defer the calculated differences between Actual Margins and Adjusted Order Granted Margins for subsequent return or recovery via the SRC. Annually, the Utility shall reflect in a revised SRC the accumulated monthly margin differences.

The accumulated monthly margin differences for each Rate Schedule shall be divided by projected throughput volumes for each Rate Schedule to determine the applicable SRC. Projected and actual recoveries by Rate Schedule under the SRC are reconciled, with any under or over recovery being recovered or returned over a subsequent twelve month period.

ENERGY EFFICIENCY ADJUSTMENT RATE: $ Per Therm

The applicable Energy Efficiency Adjustment Rate (the sum of the EEFC and SRC) shall be applied to each therm of metered gas usage each month.

Rate Schedule	A Energy Efficiency Funding Component	B Sales Reconciliation Component	A + B Energy Efficiency Adjustment Rate
Gas Rate D1	$0.0000	$0.0000	$0.0000
Gas Rate D2	$0.0000	$0.0000	$0.0000
Gas Rate D3	$0.0000	$0.0000	$0.0000
Gas Rate D4	$0.0000	$0.0000	$0.0000

GAS RATE NO. A2

USAGE BALANCING SERVICE

APPLICABILITY:

This rate is applicable to 3rd Party Suppliers providing gas supply services to a Supplier Group of End-Use Customers, or to End-Use Customers acting as their own Supply Agent, in accordance with the Utility's requirements and other End-Use Customers as applicable.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. A2, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

USAGE IMBALANCES

The Utility shall cash out monthly a 3rd Party Supplier, or End-Use Customers acting as their own Supply Agent, the following in connection with positive or negative monthly net Usage Imbalances associated with a Supplier Group of End-Use Customers, or an End-Use Customer acting as its own Supply Agent, receiving Gas Delivery Service under Gas Rate Nos. D3, D4, D5, D7 and D9.

Negative monthly net Usage Imbalances reflect situations where a Supplier Group of End-Use Customers, or an End-Use Customer acting as its own Supply Agent, consumed greater volumes of Gas than accumulated Daily Gas Supply Deliveries for the month.

GAS RATE NO. A2 – USAGE BALANCING SERVICE (Cont'd)

Positive monthly net Usage Imbalances reflect situations where a Supplier Group of End-Use Customers, or an End-Use Customer acting as its own Supply Agent, consumed lesser volumes of Gas than accumulated Daily Gas Supply Deliveries for the month.

In the event an Operational Flow Order is issued, all Usage Imbalances will be billed in accordance with Rate No. A4 Non-Performance charges. In all non-Operational Flow Order periods any net monthly Usage Imbalances will be administered in the following manner:

MONTHLY CASH-OUT:

1. Cash-out charges for net monthly negative Usage Imbalances are as follows (Charges posted to bill):

   Usage Imbalances of greater than 0% up to and including 10% will be carried over to the next month.

   110% of applicable Gas Supply Charge from Rider A (including capacity costs) for monthly net Usage Imbalances of greater than 10% up to and including 20%

   120% of applicable Gas Supply Charge from Rider A (including capacity costs) for monthly net Usage Imbalances of greater than 20% up to and including 30%

   140% of applicable Gas Supply Charge from Rider A (including capacity costs) for monthly net Usage Imbalances of greater than 30%.

GAS RATE NO. A2 – USAGE BALANCING SERVICE (Cont'd)

2. Cash-out credits for net monthly positive Usage Imbalances are as follows (Utility will purchase amounts from a 3rd Party Supplier, or End-Use Customer acting as its own Supply Agent that are not offset by other charges.):

    Usage Imbalances of greater than 0% up to and including 10% will be carried over to the next month.

    90% of applicable Gas Supply Charge from Rider A (excluding capacity costs) for monthly net Usage Imbalances of greater than 10% up to and including 20%

    80% of applicable Gas Supply Charge from Rider A (excluding capacity costs) for monthly net Usage Imbalances of greater than 20% up to and including 30%

    60% of applicable Gas Supply Charge from Rider A (excluding capacity costs) for monthly net Usage Imbalances of greater than 30%.

3. Cash out charges for volumes purchased and injected to bring a Customer Banking Volume inventory to the granted level will be charged to the End-Use Customer at the following rate:

    105% of the applicable Gas Supply Charge from Rider A or Citizens' storage WACOG, whichever is greater.

BILLING:

Charges and credits for Usage Balancing Service will be calculated monthly and billed at month end to the applicable 3rd Party Supplier, or End-Use Customer acting as its own Supply Agent or as otherwise applicable to an End-Use Customer. Utility will purchase amounts from a 3rd Party Supplier, or End-Use Customer acting as its own Supply Agent that are not offset by other charges.

GAS RATE NO. A3

BASIC USAGE BALANCING SERVICE

APPLICABILITY:

This rate is applicable to 3rd Party Suppliers providing gas supply services to a Supplier Group of End-Use Customers who have chosen the Basic Delivery Service Option, or to End-Use Customers acting as their own Supply Agent, who have elected the Basic Delivery Service Option, in accordance with the Utility's requirements.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. A3, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

BASIC USAGE IMBALANCES:

The Utility shall cash-out monthly a 3rd Party Supplier, or an End-Use Customer acting as its own Supply Agent, the following in connection with positive or negative daily net Basic Usage Imbalances associated with a Supplier Group of End-Use Customers, or for the End-Use Customer acting as its own Supply Agent, under Gas Rate Nos. D3, D4, D5, D7, and D9.

Negative daily net Basic Usage Imbalances reflect situations where a Supplier Group of End-Use Customer(s), or an End-Use Customer acting as its own Supply Agent, consumed a greater volume of Gas than its Daily Gas Supply Deliveries.

Positive daily net Basic Usage Imbalances reflect situations where a Supplier Group of End-Use Customer(s), or an End-Use Customer acting as its own Supply Agent, consumed a lesser volume of Gas than its Daily Gas Supply Deliveries.

GAS RATE NO. A3 – BASIC USAGE BALANCING SERVICE (Cont'd)

In all Non-Operational Flow Order periods any net daily Basic Usage Imbalances will be administered in the manner described below. All volumes carried to month end will be cashed out in accordance with the provisions of Rate No. A2 Usage Balancing Service.

MONTHLY CASH-OUT OF DAILY IMBALANCES:

1. Except under Operational Flow Order or Curtailment conditions, cash-out charges for negative daily net Basic Usage Imbalances are as follows:

   Daily net Basic Usage Imbalances of 0% up to and including 20% will be carried to month end.

   110% of applicable Gas Supply Charge from Rider B (including capacity costs) for daily net Basic Usage Imbalances of greater than 20% up to and including 30%.

   120% of applicable Gas Supply Charge from Rider B (including capacity costs) for daily net Basic Usage Imbalances of greater than 30% up to and including 40%.

   140% of applicable Gas Supply Charge from Rider B (including capacity costs) for daily net Basic Usage Imbalances of greater than 40%.

2. Cash-out charges for negative daily net Basic Usage Imbalances, under Operational Flow Order conditions, are as follows:

   For each Therm of a negative daily net Usage Imbalance greater than 5% percent, the greater of the highest per-unit gas cost paid by the Utility on the date of non-compliance or the daily cash-out charge as calculated above; plus

   The payment of all other charges incurred by the Utility and attributable to the 3rd Party Suppliers' imbalance, including pipeline penalty charges on the Operational Flow Order shortfall quantities; plus

   An Operational Flow Order imbalance charge of $1.00 per Therm on the portion of the daily imbalance that is greater than 5%; plus

   Applicable taxes.

GAS RATE NO. A3 – BASIC USAGE BALANCING SERVICE (Cont'd)

3. Except under Operational Flow Order or Curtailment conditions, cash-out credits for positive daily net Basic Usage Imbalances are as follows:

   Daily net Basic Usage Imbalances of 0% up to and including 20% will be carried to month end.

   90% of applicable Gas Supply Charge from Rider B (without capacity costs) for daily net Basic Usage Imbalances of greater than 20% up to and including 30%.

   80% of applicable Gas Supply Charge from Rider B (without capacity costs) for daily net Basic Usage Imbalances of greater than 30% up to and including 40%.

   60% of applicable Gas Supply Charge from Rider B (without capacity costs) for daily net Basic Usage Imbalances of greater than 40%.

4. Cash-out credits for positive daily net Basic Usage Imbalances, under Operational Flow Order conditions, are as follows:

   The Utility will pay the 3rd Party Supplier for each Therm of positive daily net Usage Imbalance greater than 5%, the lesser of the lowest per-unit gas cost paid by the Utility (excluding capacity costs) on the date of non-compliance or the daily cash-out credit as calculated above; offset by

   The 3rd Party Supplier will pay the Utility all charges incurred and attributable to the 3rd Party Supplier's imbalance, including pipeline penalty charges on the Operational Flow Order excess quantities and all applicable taxes; and

   The 3rd Party Supplier will pay the Utility an Operational Flow Order imbalance charge of $1.00 per Therm on the portion of the daily positive imbalance greater than 5%.

BILLING FOR DAILY IMBALANCE CASH-OUTS:

Basic Usage Imbalance charges and credits will be calculated daily, accumulated throughout the month and billed at month end, to the applicable 3rd Party Supplier or End-Use Customer acting as its own Supply Agent. Utility will purchase amounts from a 3rd Party Supplier, or End-Use Customer acting as its own Supply Agent that are not offset by other charges.

GAS RATE NO. D5

LARGE VOLUME DELIVERY SERVICE

APPLICABILITY:

This rate schedule applies to all Gas delivered in a Month or any portion thereof for consumption for a single End-Use Customer through one or more Meters supplying a single Premise where the End-Use Customer used a minimum of 300,000 Therms of Gas during the twelve (12) Months prior to initiation of Gas Delivery Service under this rate schedule or, in the Utility's sole judgment, is expected to use such minimum Gas volume level during the first twelve (12) Months of service under this rate schedule.

SPECIAL PROVISIONS:

Incorporated herein, and made part of this Gas Rate No. D5, are the Terms and Conditions for Gas Service, as amended from time to time. Capitalized terms used in this rate schedule are defined in the Terms and Conditions for Gas Service.

FACILITIES CHARGE:

Meter Class I - $50.00 Per Meter Per Month
Meter Class II - $150.00 Per Meter Per Month
Meter Class III - $600.00 Per Meter Per Month

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

METER CLASSIFICATIONS:

Meter Class I (CF/Hour)	Meter Class II (CF/Hour)	Meter Class III (CF/Hour)
250	8C	5000
425	800	5M
	1000	7M
	1400	11M
	2300	16M
	3000	23M
	1.5M	38M
	3M	56M
		102M
		4 Turbo
		6 Turbo
		8 Turbo
		12 Turbo

DEMAND CHARGE:

$0.4157 Per Therm of Billing Demand Per Month

Billing demand is determined as the highest average daily consumption during any one of the previous billing months of November, December, January, February and March. Billing demands will be adjusted annually, with bills issued for April consumption.

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

DELIVERY CHARGE:

$0.0349 Per Therm Delivered Each Month

In addition, applicable Balancing Charges from Rider A and Customer Benefit Distribution / Universal Service Program from Rider C shall apply to all Therms delivered.

BASIC DELIVERY OPTION:

End-Use Customers are eligible to elect the Basic Delivery Service Option, in accordance with the Utility's requirements. End-Use Customers choosing the Basic Delivery Service Option must select a 3rd Party Supplier for gas supply service, or act as their own Supply Agent.

Basic Delivery Service charges are as follows:

$0.0275 Per Therm Delivered Each Month

In addition, applicable Balancing Charges from Rider A and Customer Benefit Distribution / Universal Service Program from Rider C shall apply to all Therms delivered.

End-Use Customers choosing the Basic Delivery Service Option must have Automatic Meter Reading Devices (AMR), provided by the Utility through Information Service, under Gas Rate No. A7.

GAS SUPPLY:

This rate schedule and the above-stated charges or adjustments do not provide for a supply of Gas. Gas Supply is available from the Utility through Variable-Rate Gas Supply Service, under Gas Rate No. S1.

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

End-Use Customers choosing not to make a gas supply selection, either from the Utility, or from a 3rd Party Supplier, will receive Variable-Rate Gas Supply Service under Gas Rate No. S1.

End-Use Customers electing the Basic Delivery Service Option are eligible, but are not required, to act as their own Supply Agent. As a Supply Agent, they must be an approved bidder on CMS Panhandle Eastern Pipe Line and/or Texas Gas Transmission or their successors and are expected to perform all responsibilities normally handled by 3rd Party Suppliers. These include, but are not limited to, forecasting gas supply volumes, making pipeline and Utility Daily Gas Supply Nominations, and balancing their nominations, deliveries and usage. End-Use Customers acting as their own Supply Agent are responsible for charges for Supply Administration Service, under Gas Rate No. A1, as well as for Basic Usage Balancing Service, under Gas Rate No. A3, and, if applicable, Non-Performance Charges, under Gas Rate No. A4.

GAS SUPPLY FROM 3RD PARTY SUPPLIERS:

End-Use Customers may choose a 3rd Party Supplier to furnish a supply of Gas in accordance with the Utility's requirements. It is the End-Use Customer's responsibility to ensure that the 3rd Party Supplier delivers the directed proportion of gas supplies at delivery points designated by the Utility.

The Utility also reserves the right to bill the End-Use Customer at appropriate Gas Supply Service rates for Gas consumed in excess of Daily Gas Supply Deliveries, following cessation of any agreement with a 3rd Party Supplier.

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

Back-up Gas Supply Service, under Gas Rate No. S2, is available from the Utility to End-Use Customers for each Single Account with an annual usage at a single meter greater than 50,000 Therms, and either choosing a 3rd Party Supplier or acting as their own Supply Agent. Back-up Gas Supply Service provides for reservation of a designated level of pipeline capacity and gas supply to be available on a daily basis, in order to provide an additional measure of gas supply security. Back-up Gas Supply Service is only available to those customers choosing the Basic Delivery option and who have not opted out of Banking.

Following expiration of their contracts with 3rd Party Suppliers, and with appropriate notice, as described in the accompanying Terms and Conditions for Gas Service, End-Use Customers may choose to purchase Gas Supply from the Utility under Gas Rate No. S1, with the Utility's approval.

End-Use Customers may switch 3rd Party Suppliers once each calendar year at no charge, but will not be permitted to switch from 3rd Party Supplier to System Supply or vice versa more than one time per 12-month period. End-Use Customers who switch 3rd Party Suppliers more than once each calendar year will be subject to Switching Charges, under Gas Rate No. A8.

Gas Imbalance Provisions
Delivery Imbalances for Supplier Groups, or End-Use Customers acting as their own Supply Agent, arising from differences in the level of Daily Gas Supply Nominations compared to the level of Daily Gas Supply Deliveries will be monitored on a daily basis and accumulated monthly for all End-Use Customers of a 3rd Party Supplier, in a Supplier Group, or End-Use Customers acting as their own Supply Agent. Charges for all Delivery Imbalances will be billed, at month end, to 3rd Party Suppliers, or to End-Use Customers acting as their own Supply Agent, through Non-Performance Charges, under Gas Rate No. A4.

Usage Imbalances for Supplier Groups, arising from differences in the level of accumulated Daily Gas Supply Deliveries compared to the level of gas consumed by End-Use Customers in the Supplier Group, will be monitored, combined and netted, on a monthly basis. Unless an Operational Flow Order is issued, all monthly net Usage Imbalances will be charged, at month end, to 3rd Party Suppliers through Usage Balancing Service, under Gas Rate No. A2. In the event of an Operational Flow Order, monthly net Usage Imbalances will be charged, at month end, to 3rd Party Suppliers through Non-Performance Charges, under Gas Rate No. A4.

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

In addition to the Basic Delivery Service Charges applicable to End-Use Customers selecting Basic Delivery Service, Basic Usage Imbalances, for Basic Delivery Service customers, arising from differences in the level of Daily Gas Supply Deliveries compared to the level of gas consumed by the End-Use Customer, will be monitored for End-Use Customers acting as their own Supply Agent, or combined and netted, on a daily basis, for all End-Use Customers in a single Supplier Group. All daily net Basic Usage Imbalances will be calculated daily and charged, at month end, to 3rd Party Suppliers, or to End-Use Customers acting as their own Supply Agent, through Basic Usage Balancing Service, under Gas Rate No. A3.

Banking Service

All End-Use Customers contracting with 3rd Party Suppliers, or End-Use Customers acting as their own Supply Agent, will be granted Customer Banking Volumes for use throughout the year.

Customer Banking Volumes will be granted periodically by the Utility to each End-Use Customer based on the ratio of the End-Use Customer's winter season (November through March) consumption to total Utility winter season throughput, both for the preceding heating season times storage capacity available for banking. New End-Use Customers will be granted Customer Banking Volumes based on usage of similar End-Use Customers, if more specific information is not available.

If the End-Use Customer elects to change 3rd Party Suppliers, Customer Banking Volumes will remain with the End-Use Customer and will transfer from the former 3rd Party Supplier to the new 3rd Party Supplier, effective at the same time as the change in 3rd Party Supplier.

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

Banking Service Option
End-Use Customers selecting Basic Delivery Service, with annual usage in excess of 1,000,000 Therms, may opt-out of Banking Service on an annual basis in accordance with the following procedures. An eligible End-Use Customer must sign an agreement with the Utility to verify its intent to opt-out of Banking Service. Elections must occur during the Election Period, and are in force for a minimum twelve-month period. Elections become effective beginning April 1 and remain effective through March 31 of subsequent years, until the End-Use Customer requests to re-elect Banking Service during an Election Period. The End-Use Customer's ability to re-elect Banking Service is subject to the Utility's determination that sufficient interstate pipeline capacity, and/or on-system storage capacity, either exists, or can be procured by the Utility. Any costs incurred by the Utility to arrange for a re-election to Banking Service will be charged to the End-Use Customer returning. A reasonable estimate of the costs will be provided to the End-Use Customer before the End-Use Customer decides whether to re-elect Banking Service.

Basic Delivery Service charges for End-Use Customers that have opted-out of Banking Service are as follows:

$0.0195 Per Therm Delivered Each Month

In addition, applicable Balancing Charges from Rider A and Customer Benefit Distribution/ Universal Service Program from Rider C shall apply to all Therms delivered.

Incremental Banking Service
During the Election Period, the Utility will make available Incremental Banking Volumes, through Incremental Banking Service, under Gas Rate No. A9, to all End-Use Customers purchasing gas supply from a 3rd Party Supplier, End-Use Customers acting as their own Supply Agent or 3rd Party Suppliers. Requirements for use of Incremental Banking Volumes acquired by 3rd Party Suppliers or End-Use Customers either are identical to standard Banking Volumes as described below, or are in accordance with non-discriminatory standards determined by the Utility.

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

Nomination of Customer Banking Volumes
End-Use Customers' daily Banking Volume Injections or Withdrawals will be designated by their 3rd Party Supplier or End-Use Customers acting as their own Supply Agent. All Customer Banking Volumes requested to be injected or withdrawn must be nominated by the 3rd Party Supplier or End-Use Customers acting as their own Supply Agent, by the end of the gas day, in accordance with the required nomination procedures as described in the Terms and Conditions for Gas Service. Subject to the limitations described below, the Banking Injection or Withdrawal Nominations will be confirmed, in total or part, in the sole discretion of the Utility.

Confirmed Banking Injection or Withdrawal Nominations will be used in the determination of Delivery and Usage Imbalances.

The Customer Banking Volume injection period will be the period from April 1 through October 31, inclusive. Customer Banking Volume injections shall not be permitted from November 1 through March 31. By October 31 of each year, all Banking Injection Nominations must have been delivered to the Utility's City Gate. The maximum Banking Volume Injection Quantity ("BVIQ") is one-one hundred and fiftieth (1/150) of the Customer Banking Volume, less remaining inventory from the previous year. Banking Withdrawal and Injection Nominations will be done ratably, or in accordance with the Utility's operational needs.

Permission for Banking Injection Nominations in excess of the amounts set forth in the preceding section may be requested. Utility may, at its sole discretion, honor such request without discrimination.

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

If the granted Customer Banking Volume level is not reached by October 31, the Utility will purchase and inject the volume of Gas necessary to bring the Customer Banking Volume inventory to the assigned level and the End-Use Customer will be charged for that volume in accordance with the provisions of Gas Rate No. A2.

The Customer Banking Volume withdrawal period will be the period from November 1 through March 31, inclusive. Banking Withdrawal Nominations shall not be permitted from April 1 through October 31. The maximum Banking Volume Withdrawal Quantity ("BVWQ"), on any one day, shall be calculated as one-seventy fifth (1/75) of the granted Customer Banking Volumes. Banking Injection and Withdrawal Nominations will be done ratably or in accordance with the Utility's operational needs.

The BVWQ will be reduced as the withdrawal period progresses in accordance with the following table:

Applicable Dates	Maximum Daily Banking Withdrawal Quantity
Nov. 1 – Dec. 31	100% of BVWQ
Jan. 1 – Jan. 15	75% of BVWQ
Jan. 16 – Feb. 15	50% of BVWQ
Feb. 16 – March 31	25% of BVWQ

Permission for Banking Withdrawal Nominations in excess of the amounts set forth in the preceding section may be requested. Utility may, at its sole discretion, honor such request without discrimination.

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

Customer Banking Volumes must be maintained at or above minimum Customer Banking Volume inventory levels, expressed as a percentage of total Customer Banking Volumes, over the winter season, in accordance with the following table:

Date	Minimum Customer Banking Volume Inventory % of Total Capacity
At January 31	19%
At February 28	9%

No End-Use Customers will be allowed to switch back to Variable-Rate Gas Supply Service, under Gas Rate No. S1 during the winter season, unless the required minimum Customer Banking Volume Inventory balances noted above are maintained.

Up to 5% of Customer Banking Volumes may remain in inventory at the end of the withdrawal period (March 31) without penalty. If more than 5% of Customer Banking Volumes is left in inventory at the end of the withdrawal period, the Utility will purchase from the End-Use Customer all remaining Customer Banking Volumes above the 5% allowance. The purchase price will be the lesser of 90% of the applicable Variable-Rate Gas Supply Service, for the current month, under Gas Rate No. S1, or 90% of the Utility's Storage WACOG at March 31.

Supply of Last Resort
If the 3rd Party Supplier, or End-Use Customer acting as its own Supply Agent, defaults, as indicated by its failure to nominate and/or deliver gas supplies for three consecutive days, End-Use Customers who have contracted for gas supply services from 3rd Party Suppliers, or are acting as their own Supply Agent, will have access to Supply of Last Resort Service from the Utility, under Gas Rate

GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

No. S3, if available. Supply of Last Resort Service, if available, will be provided until the first day of the End-Use Customer's next billing cycle, at which time Variable Rate Gas Supply Service, under Gas Rate No. S1, will apply for a minimum of one billing cycle, subject to the Utility's discretion. If End-Use Customers do not have Automated Meter Reading devices, usage applicable to Supply of Last Resort Service will be prorated.

Nominations

3rd Party Suppliers of End-Use Customers in a Supplier Group, and End-Use Customers acting as their own Supply Agent, will be required to provide an estimate of Daily Gas Supply Nominations for the following month to the Utility by the required date, as stated in the Terms and Conditions for Gas Service, prior to the beginning of the month. 3rd Party Suppliers of End-Use Customers in a Supplier Group, and End-Use Customers acting as their own Supply Agent, also will be required to provide Daily Gas Supply Nominations to the Utility, as stated in the Terms and Conditions for Gas Service. The Utility retains the right to refuse Daily Gas Supply Nominations that vary significantly from the estimated daily nomination previously provided to the Utility.

Except as otherwise provided herein, 3rd Party Suppliers of Supplier Groups and Supplier Pools, and End-Use Customers acting as their own Supply Agent, are required to provide Daily Gas Supply Nominations in equal amounts on all interstate pipelines connected to the Utility's distribution system at the 3rd Party Marketer's level. The Utility will allow, on a first-come, first-served basis, End-Use Customers with annual usage greater than 1,000,000 Therms, to notify the Utility, in writing, of an intent to nominate volumes that do not comply with the previously stated requirement of equal nomination amounts on all interstate pipelines connected to the Utility's distribution system. The initial total usage of End-Use Customers that can be exempt from the requirement is 5 Bcf. As participating End-Use Customers change their nomination practices to comply with the Utility's requirement, the Utility will open a 30-day sign-up period, allocated on a first-come, first-served basis, for additional End-Use Customers interested in nominating volumes that do not comply with the Utility's requirement.

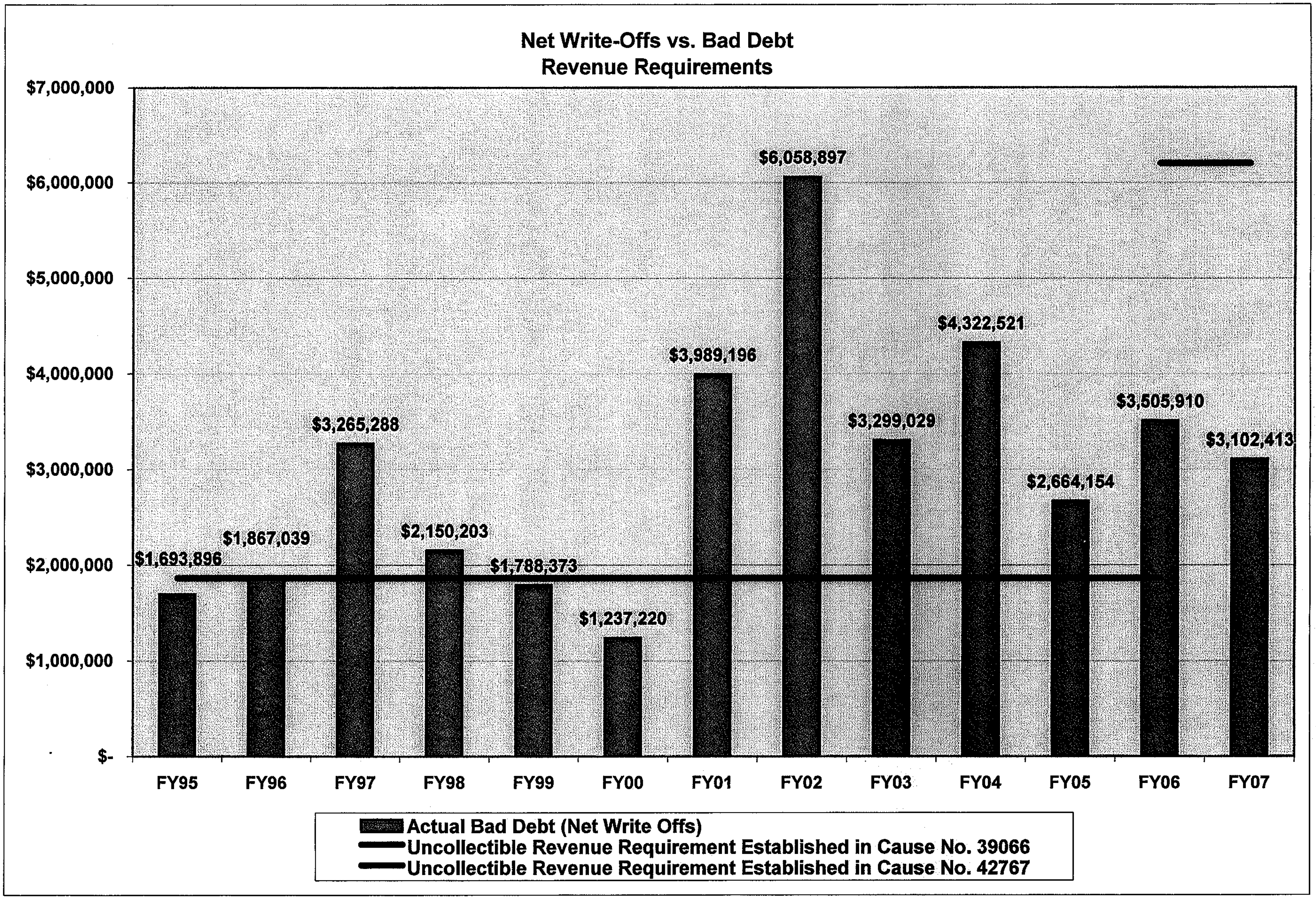
GAS RATE NO. D5 – LARGE VOLUME DELIVERY SERVICE (Cont'd)

Non-Economic Operational Flow Order
The Utility, in its discretion, shall have the right to issue a Non-Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If a Non-Economic OFO is declared, the Utility will notify the affected 3rd Party Suppliers or End-Use Customers acting as their own Supply Agent, in accordance with the Non-Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers, or End-Use Customers acting as their own Supply Agent, who do not comply with the Non-Economic Operational Flow Order, will be subject to the Operational Flow Order imbalance provisions of Basic Usage Balancing Service, under Gas Rate No. A3, or Non-Performance Charges, under Gas Rate No. A4.

Economic Operational Flow Order
The Utility, in its discretion, shall have the right to issue an Economic Operational Flow Order in accordance with the provisions stated in the Terms and Conditions for Gas Service. If an Economic Operational Flow Order is declared, the Utility will notify the affected 3rd Party Suppliers or End-Use Customers acting as their own Supply Agent, in accordance with the Economic Operational Flow Order procedures stated in the Terms and Conditions for Gas Service. 3rd Party Suppliers, or End-Use Customers acting as their own Supply Agent, who do not comply with the Economic Operational Flow Order, will be subject to the Operational Flow Order imbalance provisions of Basic Usage Balancing Service, under Gas Rate No. A3, or Non-Performance Charges, under Gas Rate No. A4.

Company Use Gas
The Utility will retain 0.6% of the volumes tendered for delivery to the End-Use Customer for Company Use Gas.

Curtailment
Service under this rate schedule may be curtailed, as described in Terms and Conditions for Gas Service. If a Curtailment is declared, the Utility will notify End-Use Customers, and 3rd Party Suppliers, as soon as practicable, but not less than 30 minutes prior to the effective time. End-Use Customers may be directed to restrict their Gas consumption on an hourly or daily basis. End-Use Customers who do not comply with the Utility's request may be subject to Non-Performance Charges, under Gas Rate No. A4, for all Gas taken in excess of the Utility's order.


Net Write-Offs vs. Bad Debt
Revenue Requirements
$7,000,000
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$-
$1,693,896
$1,867,039
$3,265,288
$2,150,203
$1,788,373
$1,237,220
$3,989,196
$6,058,897
$3,299,029
$4,322,521
$2,664,154
$3,505,910
$3,102,413
FY95
FY96
FY97
FY98
FY99
FY00
FY01
FY02
FY03
FY04
FY05
FY06
FY07
Actual Bad Debt (Net Write Offs)
Uncollectible Revenue Requirement Established in Cause No. 39066
Uncollectible Revenue Requirement Established in Cause No. 42767

CITIZENS GAS & COKE UTILITY
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for March 2008

Line No.		A Demand	B Commodity and Other	C Total
	Estimated Cost of Gas			
1	Purchased gas cost (Schedule 3, Page 1, ln 11)	$1,814,584	$24,103,604	$25,918,188
2	ADS2 Unnominated Quantities cost (Schedule 4 pg 1, ln 16 col B/3 + ln 23)	-	1,137,503	1,137,503
3	ADS7 Fuel & Variable Costs (Sch 4A, ln 3, col. H)	-	132,563	132,563
4	Gas (injected into) withdrawn from storage - net cost (Schedule 5, ln 4)	713,279	12,118,670	12,831,949
5	Other gas supply (Schedule 3B, ln 4)	-	0	0
6	Total estimated gas cost	$2,527,863	$37,492,340	$40,020,203
7	Total Gas Supply variance (total of ln 17)	-	(2,641,413)	(2,641,413)
8	Total Balancing Demand variance (total of ln 11 + Sch. 1, pg. 3, ln 1)	-	(194,806)	(194,806)
9	Dollars to be refunded (Schedule 12A, ln 16 * Sch 2B, ln 26, col. H)	-	539	539
10	Total cost before Net-Write Off to be recovered through GCA (ln 6b + ln 7 + ln 8 - ln 9)	$2,527,863	$34,655,582	$37,183,445
10a	Net Write-Off Recovery Costs (ln 10 * 0.80%)			$297,468
10b	Total cost to be recovered through GCA (ln 10 + ln 10a)			$37,480,913

CITIZENS GAS & COKE UTILITY
Determination of Gas Supply Charge with Demand Cost Allocated
Estimated for March 2008
To Be Applied to March 2008 Sales

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3	D Gas Rate No. D4	E Gas Rate Nos. D5/D9	F Gas Rate No. D6	G Gas Rate D7
	Calculation of Gas Supply Charge per Unit (Dth)							
11	Balancing Demand Cost Variance (Sch12B, pg. 2, ln 13 * Sch 2C, ln 22)	($480)	($152,834)	-	0	0	0	0
12	Throughput excluding Basic - Dth (Sch 2C, ln 1)	15,421	2,813,529	0	0	0	0	0
13	Total Balancing Demand Cost variance per unit of throughput (ln 11/ ln 12)	($0.031)	($0.054)	0	0	0	0	0
14	Retail demand cost per unit sales (Sch 1A, pg 1 ln 8)	0.314	0.463	0.257	0.434	0.268	0.381	0.214
15	Annual balancing demand cost per unit for GR D1 & D2 only (Sch 1A, pg 1, ln 11)	0.016	0.016	0	0	0	0	0
16	Total demand cost to be recovered through GCA (ln 13 + ln 14 + ln 15)	$0.299	$0.425	$0.257	$0.434	$0.268	$0.381	$0.214
17	**Total Gas Supply variance (Sch 12B, pg 1, ln 13) * (Sch 2B, ln 26)**	(6,054)	(1,768,914)	(27,978)	(715,372)	(122,689)	92	(498)
18	Dollars to be refunded ((ln 9) * Sch 2B, ln 22)	2	333	8	171	25	0	0
19	Other gas supply gas costs (ln 5, col B) * (Sch 2B, ln 22)	0	0	0	0	0	0	0
20	Other non-demand gas costs (ln 6, col B - ln 2, col B - ln 5, col B) * (Sch 2B, ln 22)	115,600	21,089,614	474,632	10,779,754	1,607,945	68	2,623
21	Total monthly non-demand costs to be recovered through Gas Supply Charge (ln 17 - ln 18 + ln 19 + ln 20)	$109,544	$19,320,367	$446,646	$10,064,211	$1,485,231	$160	$2,125
22	Sales subject to GCA - Dth (Schedule 2B, ln 1)	15,421	2,813,529	63,320	1,438,110	214,514	7	350
23	Total monthly non-demand costs per unit sales (ln 21 / ln 22)	$7.104	$6.867	$7.054	$6.998	$6.924	$22.857	$6.071
23a	Net Write-Off Recovery Cost (Sch 1C, pg 2 ln 4)	0.111	0.098	0.005	0.014			
24	ADS2 Unnominated Quantites Retail Cost (Schedule 4, pg. 1 ln 8)	0.172	0.288	0.108	0.263	0.100	0.000	0.127
25	ADS2 Balancing Cost for Gas Rates D1 & D2 only (Sch 4, pg 1, ln 15)	0.074	0.074	0	0	0	0	0
26	Gas Supply Charge to be recovered through GCA (ln 16 + ln 23 + ln 23a + ln24 + ln 25)	$7.760	$7.654	$7.419	$7.695	$7.292	$23.238	$6.412
27	Gas Supply Charge modified for Indiana Utility Receipts Tax (ln 26 / (1 - 1.40%))	$7.870	$7.763	$7.524	$7.804	$7.396	$23.568	$6.503

CITIZENS GAS & COKE UTILITY
Allocation of Net Write-Off Recovery Cost
March 2008

Line No.	Calculation of Net Write-Off Recovery Cost per Unit	A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate Nos. D3	D Gas Rate No. D4	H Total
1	Net Write-Off Recovery allocation factors FY2007 Rate Case, w/p #851a, ln. 7	0.005780	0.925191	0.001105	0.067924	1.000000
2	Net Write-Off Recovery cost (Sch. 1, ln 10a) * ln 1	$1,719	$275,215	$329	$20,205	$297,468
3	Estimated retail sales- Dth (Sch 2B, ln 1)	15,421	2,813,529	63,320	1,438,110	4,330,380
4	Net Write-Off Recovery cost per unit sales (ln 2 / ln 3)	$0.111	$0.098	$0.005	$0.014	

CITIZENS GAS & COKE UTILITY
Calculation of Actual Gas Cost Variance
September, 2007

Line No		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3	D Gas Rate No. D4	E Gas Rate Nos. D5/D9	F Gas Rate No. D6	G Gas Rate No. D7	H Gas Rate No. D8	I All GCA Classes
	Calculation of Gas Supply Variance									
1	Retail Peak day demand allocation factor Cause No. 42767	0.002302	0.649220	0.009013	0.314995	0.024436	0.000002	0.000032	0.000000	1.000000
2	Retail Throughput demand allocation factor Cause No. 42767	0.003282	0.606159	0.021174	0.322222	0.047007	0.000004	0.000152	0.000000	1.000000
3	Retail Peak day/Retail throughput demand allocation factor (ln 5 * 79%) + (ln 6 * 21%)	0.002508	0.640177	0.011567	0.316513	0.029176	0.000002	0.000057	0.000000	1.000000
4	Normalized Retail Seasonal Demand Allocation Factor Cause No. 42767	0.002246	0.656685	0.007475	0.315658	0.017885	0.000000	0.000051	0.000000	1.000000
5	Actual net Demand cost allocated (ln 3 * Schedule 7, pg. 1, ln 1)	$1,881	$480,077	$8,674	$237,357	$21,879	$1	$43	0.000000	$749,912
6	Allocated other demand costs (line 2 * (Schedule 7, pg. 1, line 5 - line 8))	(1,667)	(307,836)	(10,753)	(163,639)	(23,872)	(2)	(77)	0.000000	(507,846)
7	Allocated contracted storage costs (ln 4 * Schedule 7 pg. 1, ln 3)	1,721	503,307	5,729	241,932	13,708	0	39	0.000000	$766,436
8	Actual other gas supply costs ((Schedule 7 pg. 1, ln 6) * (Sch. 6A, ln 31)	0	0	0	0	0	0	-	0.000000	0
9	Actual other non-demand gas costs ((Sch. 7 pg. 1, ln 2 + ln 4 + ln 5 - ln 8) * (Sch. 6A, ln 30))	28,632	2,327,613	243,354	1,525,719	630,932	0	4,570	0.000000	4,760,820
10	Total actual cost of gas incurred (ln 5 + ln 6 + ln 7 + ln 8 + ln 9)	$30,567	$3,003,161	$247,004	$1,841,369	$642,647	($1)	$4,575	0.000000	$5,769,322
11	Actual cost of gas billed including Utility Gross Receipts Tax (Sch. 6A, ln 33))	$30,233	$2,609,236	$241,296	$1,663,017	$629,656	$0	$3,963	0	$5,177,401
12	Actual cost of gas billed excluding *Utility Gross Receipts Tax (ln 11 * (1 - 1.4%))*	29,810	2,572,705	237,918	1,639,735	620,841	0	3,908	0	5,104,917
12a	Net Write - Off recovered (Sch 12C, ln 3)	425	33,009	1,485	2,013					36,931
13	Variance from Cause No. 37399-GCA 95 Filing (Sch. 1, pg. 2 Sep., 2007 ln 17)	($1,509)	($126,689)	($33,928)	($109,004)	($47,975)	28	(432)	0	(319,509)
14	Refund from cause No. 37399- GCA 95 Filing (Sch. 1, pg. 2 Sep., 2007 ln 18)	0	0	0	0	0	0	0	0	0
15	Gas cost recovered to be reconciled with actual cost of gas incurred (ln.12 - ln 12a - ln 13 + ln 14)	30,894	2,666,385	270,361	1,746,726	668,816	(28)	4,340	0	5,387,495
16	Gas cost variance (over)/underrecovery (ln 10 - ln 15)	($327)	$336,776	($23,357)	$94,643	($26,169)	$27	$235	$0	$381,827

Citizens Gas & Coke Utility
Calculation of Actual Gas Supply and Balancing Demand Cost Variance
September, 2007

Line No.		A Gas Rate No. D1	B Gas Rate No. D2	C Gas Rate No. D3	D Gas Rate No. D4	E Gas Rate Nos. D5/D9	F Gas Rate No. D6	G Gas Rate No. D7	H Gas Rate No. D8	I All GCA Classes
	Calculation of Allocation Factors									
26	Retail gas sales - Dths	4,721	383,824	40,129	251,591	104,041	0	754	0	785,060
27	Standard Delivery - Dths	0	0	14,791	63,865	132,831	0	0	0	211,487
28	Basic Delivery - Dths	0	0	0	0	385,471	0	0	0	385,471
29	Total Throughput - Dths (ln 26 + ln 27 + ln 28)	4,721	383,824	54,920	315,456	622,343	0	754	0	1,382,018
30	Retail sales allocation factor (ln 26 / ln 26, col. I)	0.006014	0.488910	0.051116	0.320474	0.132526	0.000000	0.000960	0.000000	1.000000
31	Throughput subject to Balancing GCA allocation factor (ln 29 /ln 29, column I)	0.003416	0.277726	0.039739	0.228258	0.450315	0.000000	0.000546	0.000000	1.000000
	Calculation of Gas Supply Charge Recovery									
		Note: This line will include $/Dth for net write-off								
32	Gas Supply Charge Cause No. 37399 - GCA 95 (D1 & D2 excludes balancing charges) per Dth	$6.404	$6.798	$6.013	$6.610	$6.052	$10.818	$5.256	$0.000	
33	Gas Supply Charge Recovery (ln 26 * ln 32)	$30,233	$2,609,236	$241,296	$1,663,017	$629,656	$0	$3,963	-	$5,177,401
	Calculation of Balancing Charge Recovery									
34	Balancing GCA Charge Cause No. 37399 - GCA 95 Standard & Retail Customers (per Dth)	$0.083	$0.070	$0.094	$0.066	$0.157	$0.073	$0.063	$0.000	
35	Balancing GCA Charge Cause No. 37399 - GCA 95 Basic Delivery Customers (per Dth)	$0.000	$0.000	$0.005	$0.003	$0.008	$0.000	$0.000		
36	Balancing Charge Recovery - Standard & Retail (ln 26 + ln 27) * (ln 34)	$392	$26,868	$5,162	$20,820	$37,189	$0	$48	$0	$90,479
37	Balancing Charge Recovery - Basic (ln 28 * ln 35)	$0	$0	$0	$0	$3,084	$0	$0	$0	$3,084
38	Total Balancing Charge Recovery (ln 36 + ln 37)	$392	$26,868	$5,162	$20,820	$40,273	$0	$48	$0	$93,563

Citizens Gas & Coke Utility
Allocation of Gas Supply Variance

Line No.		A Gas Rate No. 1 / D1	B Gas Rate No. 2 / D2	C Gas Rate No. 3 / D3	D Gas Rate No. 4 / D4	E Gas Rate No. 6 / D5/D9	G Gas Rate No. 8 / D6	H Gas Rate No. 9 / D7	I Gas Cost Variances
	Calculation of Total Gas Cost Variances								
1	Sep., 2007 Total Gas Supply Variance (Sch 6A, pg. 1, ln 16)	(327)	336,776	(23,357)	94,643	(26,169)	27	235	381,827
2	Oct., 2007 Total Gas Supply Variance (Sch 6B, pg. 1, ln 16)	2,454	551,083	10,052	239,573	(18,326)	28	(154)	784,710
3	Nov, 2007 Total Gas Supply Variance (Sch 6C, pg. 1, ln 16)	265	(523,267)	138	(19,800)	(24,172)	33	(83)	(566,886)
3a	Net Write Off Gas Cost Variance (Sch 12C, ln 19)	(158)	9,693	(1,434)	1,122				9,223
4	Total Gas Supply Variance (over)/underrecovery (Line 1 + Line 2 + Line 3 + Line 3a)	$2,234	$374,285	($14,601)	$315,538	($68,667)	$88	($2)	$608,875
	Distribution of variances to quarters by rate class								
5	First quarter Total Gas Supply Variance (ln 4 * Sch 2B, ln 18)	$608	$85,501	($3,667)	$68,503	($19,955)	$22	$1	$131,013
6	Second quarter Total Gas Supply Variance (ln 4 * Sch 2B, ln 19)	297	16,432	(2,844)	23,741	(12,043)	22	(1)	25,604
7	Third quarter Total Gas Supply Variance (ln 4 * Sch 2B, ln 20)	379	66,373	(3,474)	54,521	(14,506)	22	(1)	103,314
8	Fourth quarter Total Gas Supply Variance (ln 4 * Sch 2B, ln 21)	950	205,979	(4,616)	168,774	(22,163)	22	(1)	348,945
	Calculation of variances for this Cause								
9	Cause No. 37399 - GCA 94 Total and Gas Rate No.6-commodity - (Sch. 12B, pg. 1, ln 8)	(3,132)	(1,683,745)	9,938	(652,778)	48,355	27	127	(2,281,208)
10	Cause No. 37399 - GCA 95 Total and Gas Rate No.6-commodity - (Sch. 12B, pg. 1, ln 7)	(1,324)	(233,539)	(8,693)	(92,844)	(108,555)	23	(157)	(445,089)
11	Cause No. 37399 - GCA 96 Total and Gas Rate No.6-commodity - (Sch. 12B, pg. 1, ln 6)	(2,206)	62,869	(25,556)	(38,253)	(42,534)	20	(469)	(46,129)
12	This Cause Total Gas Supply Variance (line 5)	608	85,501	(3,667)	68,503	(19,955)	22	1	$131,013
13	Total Gas Supply Variance to be included in GCA (Over)/Underrecovery (line 9 + line 10 + line 11 + line 12)	($6,054)	($1,768,914)	($27,978)	($715,372)	($122,689)	$92	($498)	($2,641,413)

CITIZENS GAS & COKE UTILITY
Determination of Net Write-Off Gas Cost Recoveries
For the three month period ending November 30, 2007

Line No.		A D1	B D2	C D3	D D4	E Total
	September 2007					
1	Actual Sales in Dth (Sch.6A, p.3, ln.26)	4,721	383,824	40,129	251,591	680,265
2	Net Write-Off Gas Cost Component per Therm (from schedule 1, ln.13, prior GCAs)	$0.090	$0.086	$0.037	$0.008	
3	Actual Net Write Off Gas Cost Recovery (ln.1 * ln.2)	$425	$33,009	$1,485	$2,013	$36,931
4	Net Write-Off Recovery allocation factors FY2007 Rate Case, w/p #851a, ln. 7	0.005780	0.925191	0.001105	0.067924	1.000000
5	Recoverable Net Write-Off Gas Costs (Sch.6A, p.1, ln.10, col.I * 0.80% * ln.4)	$267	$42,702	$51	$3,135	$46,155
6	Net Write-Off Gas Cost Variance (ln.5 - ln.3)	**($158)**	**$9,693**	**($1,434)**	**$1,122**	$9,223
	October 2007					
7	Actual Sales in Dth (Sch.6B, p.3, ln.26)					
8	Net Write-Off Gas Cost Component per Therm (from schedule 1, ln.13, prior GCAs)					
9	Actual Net Write Off Gas Cost Recovery (ln.7 * ln.8)					
10	Net Write-Off Allocation Factors					
11	Allocate Recoverable Net Write-Off Gas Costs (Sch.6B, p.1, ln.10, col. I, * 0.80% * ln.10)					
12	Net Write-Off Gas Cost Variance (ln.11 - ln.9)					
	November 2007					
13	Actual Sales in Dth (Sch.6C, p.3, ln.26)					
14	Net Write-Off Gas Cost Component per Therm (from schedule 1, ln.13, prior GCAs)					
15	Actual Net Write Off Gas Cost Recovery (ln.13 * ln.14)					
16	Net Write-Off Allocation Factors					
17	Allocate Recoverable Net Write-Off Gas Costs (Sch.6C, p.1, ln.10, Col. I * 0.80% * ln.16)					
18	Net Write-Off Gas Cost Variance (ln.17 - ln.15)					
19	Total Net Write-Off Gas Cost Variances (ln.6 + ln.12 + ln.18)	($158)	$9,693	($1,434)	$1,122	$9,223

Citizens Gas & Coke Utility
Main Extension Test
Current vs. Proposed

		A	B	C	D	E	F	G
Line		1992	1999	2007	1992 vs 1997 (B A)	Percent Change (D/A)	1999 vs 2007 (C-B)	Percent Change (F/B)
1	Average length of main extension - feet	2,500	2,500	2,500				
2	Average cost of main extension - $/foot	$ 7.50	$ 7.50	$ 8.00				
3	Average main extension cost (line 1 * line 2)	$ 18,750	$ 18,750	$ 20,000				
	Three Year Total Revenue Test							
4	Annual revenue per customer - 850 therms/year	$ 524	$ 558	$ 989				
5	Three year revenue (line 4 * 3)	$ 1,572	$ 1,674	$ 2,967				
6	Number of customers to qualify for extension (line 3 / line 5)	12	11	7				
	Three Year Return of Investment							
7	Gas costs based on December GCA rate - $/therm	$ 0.3006	$ 0.3412	$ 0.7984				
8	Annual gas costs per customer - 850 therms/year (line 7 * 850)	$ 255.51	$ 290.02	$ 678.64	$ 34.51	13.51%	$ 388.62	134.00%
9	Annual margin revenue (line 4 - line 8)	$ 268.49	$ 267.98	$ 310.36				
10	Three year margin revenue per customer (line 9 * 3)	$ 805.47	$ 803.94	$ 931.08	$ (1.53)	-0.19%	$ 127.14	15.81%
11	Number of customers to earn return of investment (line 3 / line 10)	23	23	21				
	Five and One-Half Year Margin Test							
12	Margin revenue test based on 5.5 years (line 9 * 5.5)	$ 1,476.70	$ 1,473.89	$ 1,706.98				
13	Number of customers to qualify for extension (line 3 / line 12)	13	13	12				

Note: Main extension cost assumes 2" plastic, to a new residential subdivision, with homes between 1,800 to 2,399 square feet

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF THE BOARD OF DIRECTORS FOR UTILITIES OF THE DEPARTMENT OF PUBLIC UTILITIES OF THE CITY OF INDIANAPOLIS, AS SUCCESSOR TRUSTEE OF A PUBLIC CHARITABLE TRUST, D/B/A CITIZENS GAS & COKE UTILITY FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE AND APPROVAL OF A NEW SCHEDULE OF RATES AND CHARGES APPLICABLE THERETO, (2) AUTHORITY, TO THE EXTENT NECESSARY AS AN ALTERNATIVE REGULATORY PLAN, TO RECOVER THE GAS COST COMPONENT OF ITS NET WRITE-OFFS IN ITS GAS COST ADJUSTMENT FILINGS, (3) AUTHORITY PURSUANT TO 170 IAC 5-1-27(F) FOR A NON-GAS COST REVENUE TEST TO DETERMINE WHEN DEPOSITS ARE REQUIRED FOR EXTENSION OF FACILITIES, (4) APPROVAL OF OTHER CHANGES TO ITS GENERAL TERMS AND CONDITIONS FOR GAS SERVICE, AND (5) APPROVAL OF NEW DEPRECIATION ACCRUAL RATES	)	**CAUSE NO. 43463**

DIRECT TESTIMONY
of
CHRISTOPHER H. BRAUN

On
Behalf of
Petitioner

Citizens Gas & Coke Utility

Petitioner's Exhibit CHB

BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher H. Braun. My business address is 2150 Dr. Martin Luther King, Jr. Street, Indianapolis, Indiana 46202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis. The City is the successor trustee of a public charitable trust and acting through the Board manages and controls the municipally-owned gas utility that is the Petitioner in this proceeding and does business as Citizens Gas & Coke Utility ("Citizens Gas" or the "Utility"). I am the General Manager of Gas Operations for Citizens Gas.

Q. WHEN WERE YOU NAMED GENERAL MANAGER OF GAS OPERATIONS?

A. October 1, 2007.

Q. WHAT OTHER POSITIONS HAVE YOU HELD WITH CITIZENS GAS?

A. Prior to being named General Manager of Gas Operations, I was the Director of Distribution Operations for Citizens Gas from November 22, 1999 through September 30, 2007. Prior to that, I held the positions of Superintendant of Utilization and Maintenance, Manager of Standards and Measurement, Manager of Fleet and Plant Services, Technical Administrator, Project Engineer, Standards and

Measurement Engineer, and Junior Engineer. I also am the Vice President of Westfield Gas Corporation d/b/a Citizens Gas of Westfield.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. In 1985, I graduated from Purdue University in West Lafayette, Indiana with a Bachelor of Science Degree in Mechanical Engineering. In 1993, I received a Master of Business Administration Degree from the University of Indianapolis. I became a Registered Professional Engineer in the State of Indiana in 1998. I have 22 years experience in the gas industry.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am the Chairman of the Indiana Pipeline Awareness Association. I also am a member of the: American Gas Association, National Society of Professional Engineers, Midwest Energy Association, American Gas Association Best Practices Benchmarking Committee, Indiana Pipeline Awareness Association, Indiana 811 (Call Before you Dig) and the Underground Safety Alliance.

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS GENERAL MANAGER OF GAS OPERATIONS FOR CITIZENS GAS.

A. I have general supervisory oversight and management responsibilities for the Utility's Gas Operations and Oil Divisions. In that capacity, I oversee and provide leadership for the employees responsible for the operation and maintenance of the gas distribution and transmission system; which includes establishing and discontinuing gas service; dispatching activities; responding to customer requests; providing safe gas service at the lowest reasonable cost; and the operation and maintenance of Citizens Gas' liquefied natural gas plants, underground storage system and oil operations.

Q. IN YOUR CAPACITY AS GENERAL MANAGER OF GAS OPERATIONS, ARE YOU FAMILIAR WITH THE AMOUNTS BUDGETED AND SPENT BY THE UTILITY EACH YEAR FOR EXTENSIONS AND REPLACEMENTS TO THE GAS DISTRIBUTION AND TRANSMISSION SYSTEM?

A. Yes, I am. I am actively involved in the ongoing review of customer needs and operational needs of the Utility, as well as, the ultimate determination of what capital expenditures are necessary from year-to-year in order for the Utility to continue to provide adequate and reliable gas service.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I sponsored Direct Testimony and Exhibits on behalf of Citizens Gas of Westfield in Cause No. 42874. In that proceeding, Citizens Gas of Westfield received Commission authority to extend natural gas service to certain un-served areas immediately adjacent to its territory.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding on behalf of Citizens Gas is to (i) describe the Utility's on-going efforts to maintain a safe, dependable gas distribution system through making annual extensions and replacements ("E&R") to the system, (ii) describe the Gas Division's annual E&R process and how these expenditures are kept to a minimum, (iii) sponsor the E&R revenue requirement element in this proceeding on behalf of Citizens Gas; (iv) describe the proposed adjustment to the E&R revenue requirement related to pipeline integrity management costs, and (v) discuss efforts made by the Utility to reduce costs.

Q. WOULD YOU PLEASE IDENTIFY THE EXHIBIT YOU ARE SPONSORING IN THIS PROCEEDING?

A. Yes. I am sponsoring the following exhibit in addition to my prepared direct testimony:

- Petitioner's Exhibit CHB–1 : Capital Expenditure Summary Chart

Q. WAS THE FOREGOING EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

EXTENSIONS AND REPLACEMENTS

Q. PLEASE DESCRIBE THE MAJOR COMPONENTS OF THE GAS DIVISION'S ANNUAL EXTENSIONS AND REPLACEMENT PROGRAM.

A. The major categories of the Utility's annual extensions and replacements program are:

- Mains

- Services
- Underground Storage ("UGS")
- Meters & Equipment
- Vehicles & Work Equipment
- Other E&R

The expenditure level within each category varies from year-to-year depending on the particular needs of Citizens Gas' system and its customers, as well as the availability of funds.

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT CHB-1.

A. Petitioner's Exhibit CHB-1 shows in summary form the actual capital expenditures and other expenses comprising the E&R expense incurred by Citizens Gas during each of the fiscal years 2005 through 2007. For comparison purposes, Petitioner's Exhibit CHB-1 also includes the capital expenditure budget for E&R expense for fiscal year 2008, which ends on September 30, 2008. The level of total capital expenditures, excluding amounts spent to comply with the Pipeline Safety Act, was $21.174 million in fiscal year 2005, $21.5 million in fiscal year 2006, and $26.521 million in fiscal year 2007 - with a three-year average of approximately $23.068 million. The historical three-year average amount of $23.068 million (with one adjustment to include the ongoing cost of complying with the Pipeline Safety Act, as described later in my testimony) has been included in Citizens Gas' revenue requirement as the amount reasonably required on a going forward basis for making extensions and replacements to the system.

Q. WHY DID CITIZENS GAS BASE ITS PROPOSED E&R REVENUE REQUIREMENT ON THE THREE-YEAR AVERAGE OF EXPENSES INCURRED DURING FISCAL YEARS 2005 THROUGH 2007?

A. Citizens Gas spent $27.448 million on extensions and replacements during the test year, but chose to use the three-year average methodology because it is more representative of the Utility's level of ongoing E&R expense, and because it is consistent with Citizens Gas' desire to request smaller, more frequent rate increases, as outlined in the testimony by Messrs. Lykins and Brehm. Notably, the proposed methodology for determining the E&R revenue requirement also is consistent with manner in which the Commission determined the Utility's E&R revenue requirement in its most recent rate case (*i.e.*, Cause No. 42767). In the Order in Cause No. 42767, the Commission found that the average of E&R expenditures incurred during fiscal years 2001, 2002, 2003 and 2004 (the test year) (*i.e.*, $20,178,972) was representative of the Utility's ongoing revenue requirement. It is my understanding that Indiana Office of Utility Consumer Counselor ("OUCC") witness Michael E. Brosch originally proposed the use of the historical four-year average, stating "test year E&R should be based on a four year average of actual expenditures." The total E&R revenue requirement approved in Cause No. 42767 was $21,027,751, which includes an allowance for pipeline integrity management spending. The use of an average of the three years since the last rate case is in keeping with both the averaging philosophy and the desire for smaller, more frequent increases.

Q. YOU MENTIONED THAT CITIZENS GAS MADE AN INCREMENTAL ADJUSTMENT TO THE THREE-YEAR AVERAGE OF ITS HISTORICAL CAPITAL EXPENDITURES IN ORDER TO DETERMINE THE PROPOSED E&R REVENUE REQUIREMENT. CAN YOU BRIEFLY DESCRIBE THE ADJUSTMENT?

A. Yes. As I will further address later in my testimony, continued compliance with the requirements of the Pipeline Safety Act of 2002 will result in approximately $927,000 of additional transmission main replacements annually. Therefore, the Utility is proposing to increase its E&R revenue requirement by $927,000 which is the actual amount spent in 2007 and my projection of the ongoing need to replace transmission main due to integrity requirements.

Therefore, as reflected in Petitioner's Exhibit CHB-1, Citizens Gas' total proposed E&R revenue requirement is:

Three year average of capital expenditures during fiscal years 2005, 2006 and 2007 (excluding Pipeline Safety Act expenses)		$23,068,000
Pipeline Safety Act Expense Adjustment	+	$927,000
Total E&R Revenue Requirement	=	$23,995,000

Q. PLEASE DESCRIBE THE TYPES OF CAPITAL EXPENDITURES THAT COMPRISE THE "MAINS" CATEGORY ON PETITIONER'S EXHIBIT CHB-1.

A. The major activities in the Mains category involve either installation of new gas main piping or replacement/relocation of gas distribution and transmission main piping. Over the three-year period summarized in Petitioner's Exhibit CHB-1, total capital expenditures required for this category were approximately $10.702 million at their highest (in fiscal year 2005), with an average of $9.743 million.

Q. WHEN IS THE INSTALLATION OF NEW GAS MAIN PIPING NECESSARY?

A. Gas main piping typically is installed to extend or modify the distribution system in order to meet new demands for service. Main extensions often are necessary to serve new gas customers. Citizens Gas installs new gas main piping in accordance with the main extension regulations established by the Commission. Installation of gas main piping also may be required for system improvement purposes to ensure that the sizing and design of the distribution network is adequate to meet gas system demand. Computer modeling is performed to determine distribution and transmission system sizing adequacy based on projected peak day system demand. In the event the system size or design is inadequate to meet customer gas demand, system improvement expenditures will be required to achieve the proper system pressure profiles.

Q. UNDER WHAT CIRCUMSTANCES DOES CITIZENS GAS REPLACE OR RELOCATE GAS MAIN PIPING?

A. Main replacements and relocations typically become necessary due to pipe age or condition and for public safety reasons. Leaking pipe detected by survey that cannot be economically repaired is replaced. Also, public improvement projects such as reconstruction of streets, curbs, sidewalks, and sewers often result in the need to replace or relocate gas piping. Citizens Gas attempts to minimize these public improvement expenses through teamwork and collaboration with the appropriate agency or contractor involved in the design and/or construction phase of the work.

For safety and dependability purposes, Citizens Gas has a policy of making planned replacements of cast iron, wrought iron, and bare steel pipe. That policy calls for the replacement of all 3 and 4-inch cast iron mains, all bare steel mains, and all wrought iron mains by 2013. This objective is adjusted from year-to-year and is impacted by actual fiscal year activity, progress, and the Utility's financial position. Originally, Citizens Gas intended to complete the foregoing main replacements by 2000. In Cause No. 42767 Citizens Gas' Vice President of Gas Operations, Lindsay C. Lindgren testified that the Utility had modified the goal due to financial constraints, but hoped to complete the replacements by 2010. The timeline for completing the objective has been further extended to 2013 due to lack of available funds.

Citizens Gas also implemented a program to replace and/or repair large diameter cast iron mains dependent on age, condition, and other operating considerations, using a risk assessment process. The major impetus behind this program is customer and general public safety. The replacement program also serves to lower the system leakage rate, which indirectly results in O&M savings.

Q. PLEASE DESCRIBE THE TYPES OF CAPITAL EXPENDITURES THAT COMPRISE THE "SERVICES" CATEGORY ON PETITIONER'S EXHIBIT CHB-1.

A. The majority of the activity in the "Services" category involves installation and replacement of service piping for reasons and business practices similar to the "Mains" category. Installation of new services is necessary to serve the needs of new gas customers and varies based on economic growth, business development, and marketing activity in Marion County. As with mains, service replacements are required due to pipe age or condition, for public safety reasons, leaking pipe detected by survey that cannot be repaired economically, and for public improvement purposes, such as reconstruction projects involving streets, curbs, sidewalks, and sewers.

Over the three-year period summarized in Petitioner's Exhibit CHB-1, the total expenditures in the "Services" category were approximately $3.633 million (FY

2005), \$3.504 million (FY 2006) and \$5.576 million (FY 2007), with an average of \$4.238 million.

Q. DOES CITIZENS GAS HAVE A POLICY REQUIRING THE REPLACEMENT OF CAST IRON, BARE STEEL, AND WROUGHT IRON SERVICE PIPE?

A. Yes. As with the replacement of mains, the Utility has a policy requiring planned replacement of cast iron, wrought iron, bare steel, and poor condition service pipe on an ongoing basis. Resource constraints likewise have affected the service replacement program. The original replacement target goal of 2000 has been extended to 2010. The replacement activity also serves to minimize the number of system leaks, which results in operations and maintenance savings for Citizens Gas and its customers, and helps to avoid potentially catastrophic accidents.

Q. DOES CITIZENS GAS HAVE A FORMAL INSPECTION AND TESTING PROGRAM FOR MAINS AND SERVICES?

A. Yes. Citizens Gas' inspection and testing program conforms to federal and state requirements, and sound industry practice. This program involves scheduled pipeline surveillance, cathodic protection inspection, and leak survey testing that often result in systematic replacements of gas mains and services. Citizens Gas conducts a leak survey inspection of the entire gas main and service system at least every five years, with bare steel services being inspected and tested every three years. The Utility also inspects cast iron and transmission mains on a more frequent basis. An ongoing main and services inspection and replacement program is necessary to protect against leakage and potentially catastrophic accidents.

Q. PLEASE DESCRIBE THE TYPES OF CAPITAL EXPENDITURES THAT COMPRISE THE "UNDERGROUND STORAGE (UGS)" CATEGORY ON PETITIONER'S EXHIBIT CHB-1.

A. Typical expenses included in this category are station piping and transmission line replacements, compression and treating-related equipment replacements, well equipment replacements, and horizontal well drilling. As reflected in Petitioner's Exhibit CHB-1, the total expenditures were approximately $355,000 (FY 2005), $95,000 (FY 2006) and $1,076,000 (FY 2007), with an average of $509,000.

Q. PLEASE DESCRIBE THE TYPES OF CAPITAL EXPENDITURES THAT COMPRISE THE "METERS & HOUSE REGULATORS" CATEGORY ON PETITIONER'S EXHIBIT CHB-1.

A. This category generally includes the installation of new meters, regulators, and associated equipment. Installation of new meters is required for new customer hookups, replacement of defective meters, and replacement of old and obsolete meters. Installation of new regulators is required for similar reasons, as well as to convert portions of the distribution main system from low pressure. Petitioner's Exhibit CHB-1 shows the necessary annual expenditures for Meters & House

Regulators averaged approximately $1.811 million over a three-year period, with a minimum level of $1.769 million (FY 2007) and a maximum level of approximately $1.870 million (FY 2006). In my opinion, this level of activity is necessary to maintain accurate customer metering and safe system operating pressure levels.

Q. PLEASE DESCRIBE THE TYPES OF CAPITAL EXPENDITURES THAT COMPRISE THE "VEHICLES & WORK EQUIPMENT" CATEGORY ON PETITIONER'S EXHIBIT CHB-1.

A. Citizens Gas has a fleet of vehicles and work equipment, which are used to maintain and expand its gas delivery service. The vehicle and work equipment fleet is evaluated in detail annually to establish requirements for replacements, additions, and retirements. The primary objective of the review process is to establish and maintain a reliable, effective, and dependable fleet, while at the same time optimizing operations, maintenance, and replacement costs. Citizens Gas uses a computerized inspection and maintenance program that factors in equipment age, condition, repair history, and usage to inform the decision-making process for fleet repair and/or replacement. The fleet and equipment replacement requirement pattern is fairly constant, but the capital investment fluctuates with level and type of replacement activity, capital costs, and financial resources available. Over the three-year period reflected on Petitioner's Exhibit CHB-1, the total expenditures on vehicles and work equipment averaged $1.052 million.

Q. PLEASE DESCRIBE THE TYPES OF CAPITAL EXPENDITURES THAT COMPRISE THE "OTHER EXTENSIONS & REPLACEMENTS -- GAS" AND "CORP" CATEGORIES ON PETITIONER'S EXHIBIT CHB-1.

A. Items covered in the Other E&R categories generally include enhancements to critical infrastructure security, building and plant modifications, conventional office equipment, technical office equipment and furniture, modular workstations, computers and related equipment, telephone and communication equipment, safety equipment, operational tools, and backup electrical equipment. The most significant expenditure during the test year related to the purchase and installation of new computer hardware and software. In addition, Citizens Gas completed some necessary renovations to its general office in 2006 and 2007.

Q. IN YOUR OPINION, IS THE AMOUNT INCLUDED IN CITIZENS GAS' PROPOSED REVENUE REQUIREMENT FOR "OTHER EXTENSIONS & REPLACEMENTS" REASONABLY REPRESENTATIVE OF THE ONGOING LEVEL OF THIS CATEGORY OF E&R EXPENSE?

A. In my opinion, yes. As reflected on Petitioner's Exhibit CHB-1, Citizens Gas has budgeted \$8.695 million for Other E&R in 2008. Moreover, the types of expenditures incurred during the test year are not uncommon. Citizens Gas must frequently upgrade its computer systems and software to better serve customers. In 2008, it will be necessary for the Utility to upgrade its customer information software.

In addition, due to the age of the Utility's general office, further renovations are scheduled to be completed in the 2008 and 2009 fiscal years, with additional ongoing maintenance likely to be necessary in the future.

Nonetheless, the amount of the capital expenditures in 2006 and 2007 for Other E&R exceeds amounts incurred during prior years. However, Citizens Gas' proposal to use a three-year average of actual expenditures during fiscal years 2005, 2006 and 2007 "normalizes" the amount included in the Utility's proposed revenue requirement. Over the three-year period, the Utility's total expenditures for Other E&R averaged $5.717 million. Accordingly, the amount included in Citizens Gas' proposed revenue requirement is similar to the amount of Other E&R expense incurred by the Utility in fiscal year 2006 ($6.585 million) and in fiscal year 2007 ($7.142 million).

PIPELINE INTEGRITY MANAGEMENT

Q. IN CAUSE NO. 42767, DID CITIZENS GAS PROPOSE A *PRO FORMA* ADJUSTMENT TO ITS PROPOSED E&R REVENUE REQUIREMENT RELATING TO PIPELINE INTEGRITY MANAGEMENT SIMILAR TO THAT BEING PROPOSED IN THIS PROCEEDING?

A. Yes. In Cause No. 42767, Citizens Gas proposed to increase its E&R revenue requirement by $848,779 for costs associated with pipeline integrity management. Neither the OUCC nor the Citizens Industrial Group recommended any changes to the incremental amount of $848,779. The Commission included $848,779 for a pipeline integrity management adjustment in the approved E&R revenue requirement.

Q. PLEASE BRIEFLY DESCRIBE THE PIPELINE INTEGRITY MANAGEMENT REGULATIONS APPLICABLE TO CITIZENS GAS.

A. As part of the Pipeline Safety Act of 2002, the Department of Transportation's Research and Special Programs Administration ("RSPA"), Office of Pipeline Safety ("OPS"), issued regulations covering gas pipeline integrity management in "high consequence areas" ("HCAs"). The regulations are found at 49 CFR Part 192, Subpart O – "Pipeline Integrity Management." Pipelines in HCAs require a higher level of protection due to impact and potential harm from a pipeline failure. The goal of the OPS pipeline integrity efforts is to reduce the risk and consequence of pipeline failure in areas with higher population density and/or areas where people tend to congregate. The RSPA regulations require natural gas pipeline operators to:

- Develop and implement a comprehensive integrity management program for pipeline segments where a failure would have the greatest impact on the public or property.
- Identify and characterize applicable threats to pipeline segments that could impact a HCA.
- Conduct a "baseline integrity assessment" and periodic reassessments of these pipeline segments.

- Mitigate significant defects discovered from the assessment.
- Continuously monitor the effectiveness of the integrity management program and modify the program as needed to improve its effectiveness.

Q. WHEN DOES CITIZENS GAS NEED TO BE IN COMPLIANCE WITH THE REGULATIONS?

A. Citizens Gas already has met a number of deadlines imposed under the regulations, including performing a "baseline integrity assessment" on the "highest risk" 50% of its facilities. A baseline integrity assessment of all applicable facilities must be completed by December 17, 2012. The regulations also call for ongoing reassessments thereafter.

Q. DID CITIZENS GAS MAKE ANY CAPITAL EXPENDITURES RELATING TO THE PIPELINE SAFETY ACT PRIOR TO FISCAL YEAR 2007?

A. For the most part, no. In fiscal year 2005, capital expenditures for pipeline integrity management were approximately $32,000 and in fiscal year 2006 Citizens Gas did not make any expenditures relating to the new regulations. Because Citizens Gas spent virtually nothing in 2005 and 2006, using an average of pipeline integrity expenditures during fiscal years 2005, 2006 and 2007 would significantly understate the ongoing cost of complying with the Pipeline Safety Act. Accordingly, Citizens Gas has included the amount spent during the test year for pipeline integrity management (i.e., $927,000) in determining its extensions and replacements revenue requirement.

Q. HOW MUCH OF CITIZENS GAS' PIPELINE SYSTEM IS COVERED BY THE PIPELINE SAFETY ACT AND THE NEW REGULATIONS?

A. Citizens Gas estimates that approximately 150 miles of transmission piping is subject to the integrity regulations.

Q. WHAT ADDITIONAL CAPITAL EXPENDITURES ARE ASSOCIATED WITH COMPLYING WITH THE PIPELINE SAFETY ACT AND THE REGULATIONS?

A. Compliance with the Pipeline Safety Act and regulations requires incremental annual resource commitments. In order to comply with the inspection requirements, Citizens Gas must incur additional costs related to hydrostatic pressure testing, direct assessment via inspection, and/or physical data and record review. Citizens Gas also incurs additional costs related to remedying problems identified by the inspections. Based on Citizens Gas' experience operating under the new regulations thus far, it is anticipated that the Utility will experience ongoing annual replacements of $927,000 as was experienced in 2007.

Q. WHY IS THE ANNUAL COST ASSOCIATED WITH PIPELINE INTEGRITY MANAGEMENT SLIGHTLY HIGHER THAN ESTIMATED IN CAUSE NO. 42767?

A. Increases in the cost of material, labor and fuel and the uncertainty in the amount of pipe required to be replaced resulted in the need for a slight adjustment in the funding level.

Q. MR. BRAUN, DO YOU HAVE AN OPINION AS TO THE ANNUAL AMOUNT CITIZENS GAS REASONABLY SHOULD EXPEND TO MEET ITS REVENUE REQUIREMENT FOR EXTENSIONS & REPLACEMENTS TO ITS SYSTEM?

A. Yes. In my opinion, Citizens Gas' annual revenue requirement for extensions and replacements is $23.995 million which was developed as previously described and is shown on Petitioner's Exhibit CHB-1.

OPERATIONAL AND COST SAVING INITIATIVES

Q. PLEASE DESCRIBE EFFORTS THE UTILITY HAS TAKEN SINCE CAUSE NO. 42767 TO HOLD DOWN COSTS WITHIN THE GAS DIVISION.

A. The operational goal of Citizens Gas is to obtain and deliver gas utility service through safe, dependable systems to all available markets at the lowest feasible costs. Accordingly, Citizens Gas has made significant efforts to reduce costs over the last several years, including:

- **Heartland Gas Pipeline** -- The new pipeline provides customers with access to Western U.S. and Canadian gas. The pipeline also provides an additional source of natural gas should gulf coast supplies be interrupted by weather (*i.e.*, hurricanes such as Katrina, Rita), acts of terrorism or catastrophe.

- **Gas Supply Portfolio Review** – The Utility performs an annual supply portfolio review to determine the optimum mix of pipeline capacity and off-system storage. Changes in 2006 resulted in annual savings of $3,000,000 per year in demand savings. The 2008 review of supply mix will result in reduction off-system storage for the 2008/9 winter heating season which will provide approximately $1,000,000 in additional annual savings to our customers, a result of declining demand.
- **Storage Field Verification Studies** -- As the price of natural gas has appreciated in recent years, we have embarked upon a business process of having an independent reservoir engineering firm (Dowdle & Associates, Houston, TX) verify the booked volumes of stored gas in each of the storage fields. This process validates the Utility's annual well logging, reservoir engineering and metering processes and satisfies both internal and external auditing groups that Citizens Gas is accurately accounting for all gas stored in the storage fields. To date, Citizens Gas has successfully completed studies on the Mineral City, Switz City, Howesville and Dixon Fields, with no inventory adjustment recommended. We currently are performing field testing on

Worthington Field (to be completed by September 30, 2008) and Simpson Chapel Field is slated for study in 2009.

- **Distribution Operations Improvements** -- These improvements include: purchase of a Vacuum excavation truck to reduce paving restoration costs; utilizing existing workforce for new service work and service replacements to eliminate use of contractors; using cell phones to call customers before executing service orders to eliminate costly repeat trips; purchase of new hydraulic grease guns to repair valves that would have required costly replacement; restructuring Distribution Operations to maximize the availability of field supervision, which results in reduced manning, overtime, fleet and equipment requirements; developing standard procedures and approvals for dispatch to reduce the need for overtime; increasing focus on training to ensure consistency and efficiency in all areas of field work; moving the Cathodic Protection read responsibility to the Cathodic Protection Technicians to allow Gas Service Specialists to focus on atmospheric corrosion and other core requirements; replacing individual carbon monoxide, Gas Tracker and Gas Indicator units with a single lower cost unit; and utilizing technology to reduce manning in the office.
- **Gas Supply Staffing** -- Citizens Gas has created system/process efficiencies that have allowed one exempt gas supply analyst position to be migrated to

the Engineering area. In addition, the Utility's computer systems were improved, which has allowed one Gas Controller position to be reassigned as a System Technician. The System Technician fills the requirement of a part-time Gas Controller as needed and assists in field work.

- **LNG North Improvements** -- These improvements include: installing a Rolls-Royce turbine control panel and control system; establishing a bi-annual maintenance contract with Rolls-Royce to improve turbine reliability; replacing Plant DCS with new Delta V hardware and software; replacing the molecular sieve in the purification system to improve feed gas quality and minimize coldbox freeze ups; installing an air manifold to allow use of all plant compressors to supply both the instrument and buffer air; modifying shift schedules to increase productivity and eliminate downtime; creating 10-hour "Flex Shifts" for holding cycle instead of consistent 12-hour shift schedules; and establishing written procedures to streamline annual audits.
- **LNG South Improvements** -- These improvements include: design, fabrication and installation of new ethane feed system, since ethane concentration in the feed gas has fallen below retrievable quantities; rebuilding and re-grouting the compressor and turbine to improve performance and eliminate vibration; replacing molecular sieve in the purification system to improve feed gas quality and minimize coldbox freeze

ups; modifying a section of the coldbox to minimize leakage and improve production rate; rebuilding sendout compressor; modifying shift schedules to increase productivity and eliminate downtime; creating 10- hour "Flex Shifts" for holding cycle instead of consistent 12-hour shift schedules; establishing several written procedures to streamline annual audits.

- **Corrosion Inhibition of Underground Storage Gas Transmission Lines --** Beginning in 2008, Citizens Gas began adding corrosion inhibitors to the dewatering chemical dripped into the gas stream at the storage wellhead assemblies. The goal is to minimize the potential for internal corrosion of the transmission piping by coating the inside of the gas piping from the wellhead to the gas conditioning stations at the point where the gas is desulfurized and dehydrated. The use of corrosion inhibitors is an outgrowth of the Office of Pipeline Safety's reclassification of the Utility's lines from "gas gathering" to "gas transmission."
- **"Pigging" of Underground Storage Field Transmission Lines:** Since the reclassification of Citizens Gas' lines, the Utility has "pigged" liquids from its lines at the end of each withdrawal season. Currently, this practice is limited to the Worthington and Switz City Fields because they are the only fields with "pig" launcher/catchers installed. Citizens Gas will have the ability to "pig"

the Howesville Field in 2008. This practice will limit the potential for corrosion to occur on the inside of the piping.

- **Howesville Underground Storage Field Transmission Line Replacement:** The main trunk lines at the Howesville Field, which transport the gas from the wells to the station, will be replaced in 2008. The existing lines were installed in 1961. This replacement is part of an ongoing strategy to replace all of the transmission lines, as needed.
- **Benchmarking Efforts to Improve Efficiency** -- Citizens Gas participates in industry benchmarking efforts, including the American Gas Association's Operations Best Practices Benchmarking Program, to ensure that best practices are used to improve operations and reduce costs. In addition to receiving valuable insight from peer natural gas distribution utilities, collaborating with other utilities in benchmarking programs requires that the Utility undertake a deeper analysis of work being performed and related costs than might otherwise be completed. The following is a summary of the changes we have identified and implemented as a result of our benchmarking efforts:
    - Combination of the transmission regulating area with the gas supply area, resulting in annual savings of $240,000;

- Combination of the hauling area with the underground maintenance area, resulting in annual savings of $480,000;
- Reengineered four crews, resulting in annual savings of $320,000;
- Addition of pavement breakers to all backhoes resulting in improved efficiencies and annual savings of $80,000;
- Use of a transportation routing program to schedule cathodic protection reads improving productivity of this function by 50%; and
- Adoption of optical methane detection technology improving leak survey productivity and accuracy.

Q. HAS CITIZENS GAS ALSO TAKEN OPERATIONAL STEPS TO IMPROVE SAFETY?

A. Yes. Over the last several years, Citizens Gas has taken a number of other steps to improve safety. In addition to the employee safety initiatives outlined in Mr. Lykins testimony, Citizens Gas has implemented a number of operational safety initiatives:

- **Leak Response Times** -- Citizens Gas continuously monitors and makes improvements to response times to customer notification of gas odors. The Utility has improved average response times by over 5% in the last year to less than 37 minutes.
- **Indiana Pipeline Awareness Association ("INPAA") Activities** -- As Chair of the INPAA, I coordinate public awareness activities for all local

distribution companies in the State of Indiana to maximize effectiveness and minimize costs. Recent INPAA activities include: producing radio and television advertisements on how to respond to a gas odor directed to all residents of the State; coordinating education of emergency responders and public officials through a statewide annual training program; providing educational materials to all Indiana excavators explaining the "call before you dig" requirements of IAC 8-1-26; and assisting in the Indiana activation of the national 811 call system.

- **LNG Plants** -- Citizens Gas has installed a new carbon dioxide ("CO_2") fire retardant system in the turbine enclosure at LNG North and replaced all Halon fire extinguishers with CO_2 extinguishers at both plants; updated the security access card reader system and installed new security cameras at both plants; updated fence security system with new controller and installed a new Flammable Gas Detection system and tied it into the Delta V control system at both plants.
- **In-Line Hydrogen Sulfide and Moisture Detection** -- In-line continuous measuring hydrogen sulfide ("H_2S") and moisture detection analyzers are scheduled to be installed at Howesville, Dixon, Worthington and Mineral City Gas Conditioning Facilities in 2008. The equipment was purchased in late fiscal year 2007 and will be installed at the end of this withdrawal season (late

spring). This equipment will allow "real time" automatic sampling and recording of H2S and moisture content of the gas streams being moved through the conditioning facilities. This information will be helpful in tracking desulfurization and dehydration process equipment performance as well and, ultimately, minimizing corrosion potential in downstream piping.

- **Leak survey of Underground Storage "Field Transmission Lines" --** Since the reclassification of the Utility's lines, Citizens Gas has performed flame ionization leak surveys (via walking) twice annually, as opposed to once each year. No change in leak detection frequency has been noted.

Q. WHAT BENEFITS DOES THE UTILITY REALIZE AS A RESULT OF ITS EMPHASIS ON SAFETY?

A. The most important benefit the Utility realizes as a result of our emphasis on safety is that its customers and employees are less likely to suffer injuries. In addition to the benefit of protecting customers and employees, improved safety has financial consequences as well. Serious injuries can result in significant claims that drive up the cost of operating the Utility. Consequently, not only is improving safety for customers and employees simply the right thing to do, it ultimately reduces the cost of supplying gas to customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, at this time.

VERIFICATION

STATE OF INDIANA)
) ss:
COUNTY OF MARION)

The undersigned, Christopher H. Braun, under penalties of perjury and being first duly sworn on his oath, says that he is the General Manager of Gas Operations for Citizens Gas & Coke Utility; that he caused to be prepared and read the foregoing Verified Direct Testimony; and that the representations set forth therein are true and correct to the best of his knowledge, information and belief.

By: Christopher H. Braun
General Manager of Gas Operations
Citizens Gas & Coke Utility

Subscribed and sworn to before me, a Notary Public, this 17th day of March, 2008.

Ann Dunavent
Signature

ANN DUNAVENT
Printed Name

NOTARY PUBLIC SEAL

My Commission Expires: 08/11/08

My County of Residence: Hancock

Citizens Gas Coke Utility
Calculation of Proforma Capital Expenditures
For the 2008 Cost of Service Study

Petitioner's Exhibit
CHB-1

	Actual 2005	Actual 2006	Actual 2007	3 yr Avg		Budget 2008
Mains	$10,702	$8,914	$9,612	**$9,743**		$10,411
Meters and House Regulators	$1,793	$1,870	$1,769	**$1,811**		$1,850
Other Ext & Replacements -- Gas	$1,840	$879	$2,386	**$1,702**		$1,664
Services	$3,633	$3,504	$5,576	**$4,238**		$5,200
Underground Storage (UGS)	$355	$95	$1,076	**$509**		$255
Vehicles & Work Equipment	$1,269	$541	$1,346	**$1,052**		$770
Subtotal	$19,592	$15,803	$21,765	**$19,053**		$20,150
Other Ext & Replacements -- Corp	$1,883	$6,793	$5,662	**$4,779**		$8,370
% Gas	84%	84%	84%	**84%**		84%
Sub-Total	$1,582	$5,706	$4,756	**$4,015**		$7,031
Total E&R Excluding Pipeline Integrity	$21,174	$21,509	$26,521	$23,068		$27,181
Pipeline Integrity	$ 32	$ -	927	**$927**		$1,000
Grand Total	$21,206	$21,509	$27,448	**$23,995**		$28,181

CERTIFICATE OF SERVICE

The undersigned hereby certify that a copy of the "Direct Testimony and Exhibits of LaTona S. Prentice and Christopher H. Braun" was served this 18th day of March, 2008 by personal delivery or First Class United States mail on the following:

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